Proposed Reference System Plan

CPUC Energy Division

September 18, 2017

Contents

Acronyms & Abbreviations

AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
BANC	Balancing Area of Northern California
BTM	Behind-the-Meter
Btu	British thermal unit
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
CRVM	Common Resource Valuation Methodology
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DR	Demand Response
DRP	Distributed Resources Plan
EE	Energy Efficiency
EV	Electric Vehicle
GHG	Greenhouse Gas
IC	Internal Combustion
IDER	Integrated Distributed Energy Resource
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan (or) Planning
IRP 2017-18	The first cycle the CPUC's new IRP process
ITC	Investment Tax Credit
GW	Gigawatt
LBNL	Lawrence Berkeley National Laboratory

LNBA	Locational Net Benefit Analysis
LSE	Load Serving Entity
$MM	Millions of Dollars
MMBtu	Millions of British thermal units
MMT	Million Metric Tons of Carbon Dioxide
MW	Megawatt
MWh	Megawatt hour
NEM	Net Energy Metering
NOx	Nitrogen Oxide
NQC	Net Qualifying Capacity
OOS	Out-of-state
OTC	Once Through Cooling
PCC	Portfolio Content Category
PM 2.5	Particulate Matter, 2.5 microns
POU	Publicly-owned utility
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PV	Photovoltaic
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RPS	Renewables Portfolio Standard
SB	Senate Bill
ST	Steam Turbine
TOU	Time-of-Use
TPP	Transmission Planning Process
TRC	Total Resource Cost
TWh	Terrawatt hours
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle
ZNE	Zero Net Energy

EXECUTIVE SUMMARY

Purpose of Integrated Resource Planning (IRP)

- California's goal is to reduce statewide greenhouse gas (GHG) emissions 40% below 1990 levels by 2030.
- The electric sector currently represents 19% of total statewide GHG emissions.
  - In 1990, the electric sector represented 25% of the statewide total.
- The purpose of IRP is to ensure that the electric sector is on track to help California achieve its statewide 2030 GHG target at least cost while maintaining the reliability of the grid.
- In IRP 2017-18, Staff propose to use a capacity expansion model called RESOLVE to identify optimal portfolios of resources that will achieve electric sector GHG reductions, reliability needs, and other policy goals at least-cost under a variety of possible future conditions.

IRP Reference System Plan Proposal

- The Reference System Plan contains the main conclusions and recommendations from Staff's analytical work that should inform the development of load-serving entities' (LSEs') plans.
- Staff proposes a Reference System Plan for the Commission's consideration that contains four key recommendations:
  - A GHG Planning Target to use for the electric sector in IRP that is consistent with 40% statewide reductions by 2030 and 80% by 2050
  - A Reference System Portfolio – a single portfolio of incremental resources that represents a least-cost, least-risk pathway to achieving the recommended GHG planning target
  - A GHG Planning Price that represents the marginal cost of GHG abatement associated with the Reference System Portfolio and that will enable the CPUC and load-serving entities to consistently value both demand and supply-side resources
  - Near-term Commission policy actions to ensure that the results from IRP modeling inform other CPUC proceedings and lead to the development or procurement of adequate resources

Core Policy Cases Modeled

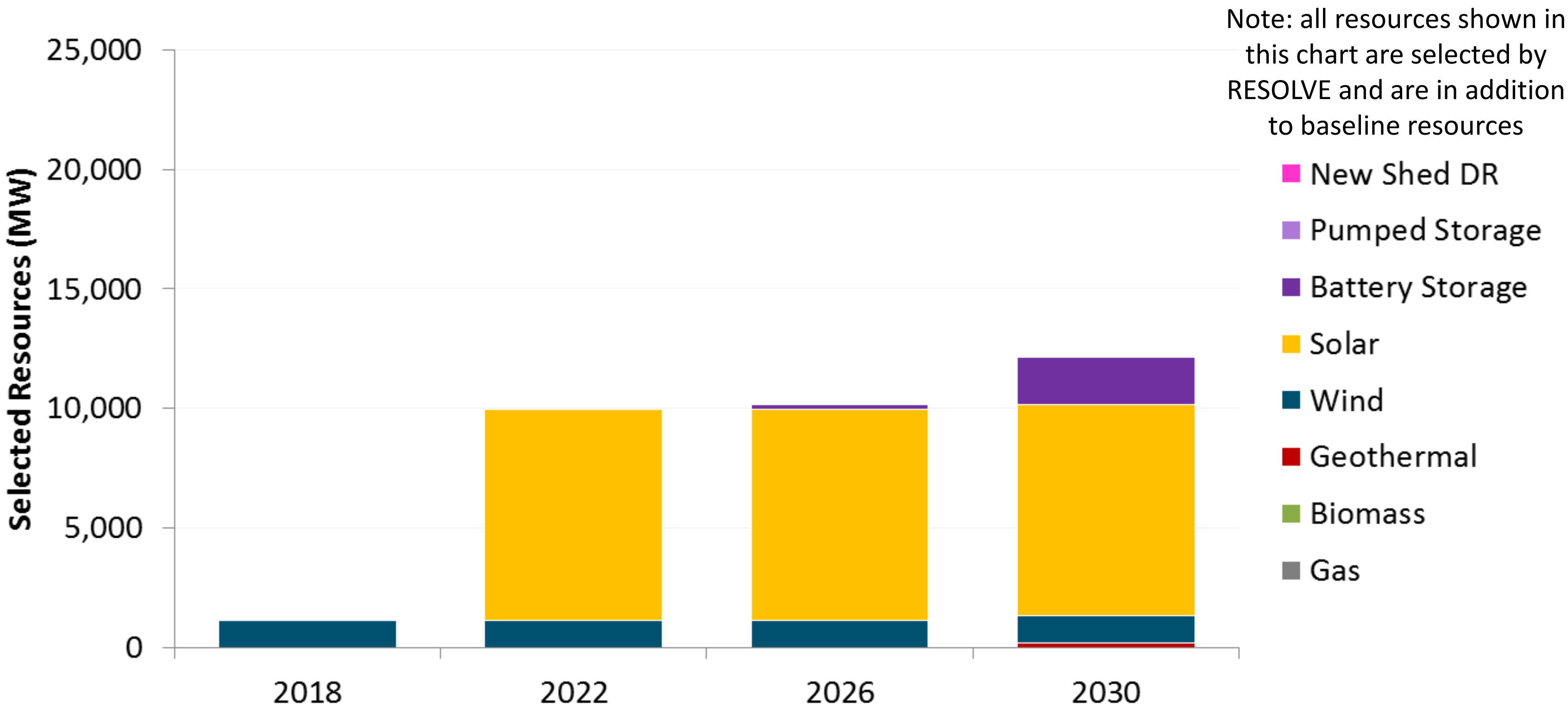
- Staff modeled three core policy cases to understand how different electric sector GHG Planning Targets may impact resource build-out requirements, costs, and risk.
- Each of these cases reflects the resources and procurement that is reasonably expected to occur based on existing policies, which is reflected in the Default Case.
- The two additional cases are based on analysis in CARB's 2017 Climate Change Scoping Plan Update (January 2017)
  - **Default Case:** Reflects all existing policies, notably the 50% RPS, and is equivalent to statewide electric sector emissions of ~51 MMT
  - **42 MMT Case:** The low end of the estimated range for electric sector emissions in CARB's Scoping Plan; it reflects a scenario in which the state GHG reduction goal is achieved with 40-85 MMT of reductions from unknown measures
  - **30 MMT Case:** The electric sector emissions in CARB's Scoping Plan scenario in which state GHG reduction goal is achieved with known measures

GHG Planning Target for the Electric Sector in IRP

- **Staff Recommended GHG Planning Target for IRP: 42 MMT by 2030**
  - A 42 MMT statewide target means that emissions from the statewide electric sector will total 42 million metric tons (MMT) in 2030, a decline of 61% from 1990 levels of 108 MMT for the sector.
  - 42 MMT statewide electric sector planning target for IRP is consistent with a straight-line trajectory of emissions reductions to meet California's goal to reduce statewide emissions 80% below 1990 levels by 2050
  - A 42 MMT target by 2030 represents a 50% decrease in electric sector emissions from 2015 levels.
  - 42 MMT target results in lower overall costs and financial risk than a 30 MMT target in 2030.
  - Differences in 2038 GHG planning targets studied and load forecasts on the path to 2050 do not affect the composition of 2030 resource portfolios, which implies there are risks associated with reducing electric sector emissions too aggressively in the near term.
  - Current CPUC policies alone may not be aggressive enough to meet the 2030 GHG Planning Target at lowest cost.

Recommended Reference System Portfolio

- **Recommended Portfolio of Additional Resources to Meet 42 MMT Planning Target**
  - Model selects ~9 GW of new utility-scale solar; 1,100 MW in-state wind; and 2,000 MW battery storage in addition to baseline that reflects existing policies
  - Total incremental cost is $239 million/year, equivalent to approximately a 1% increase in system average rates by 2030



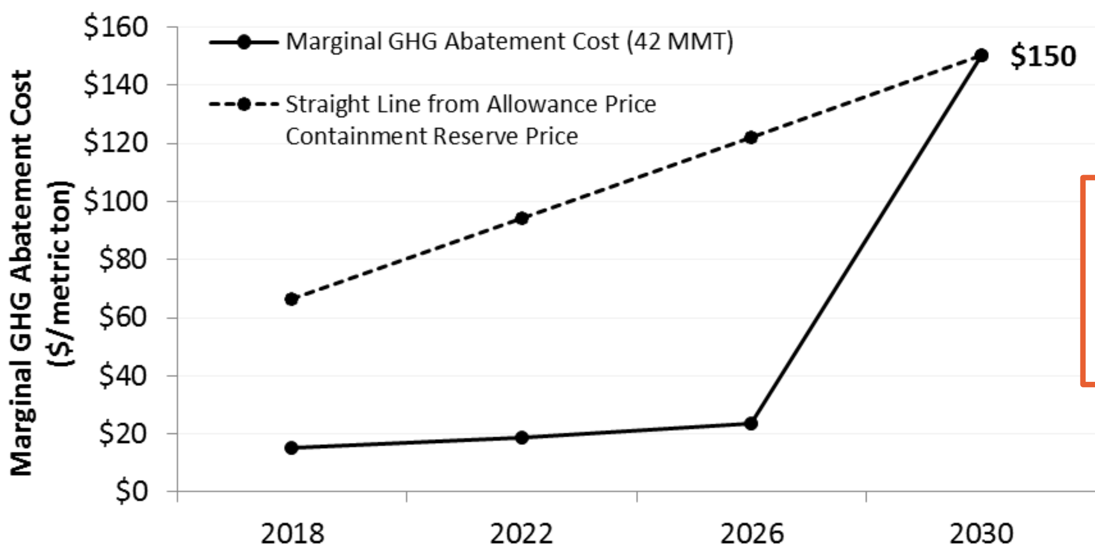
A portion of the need for short-duration services represented by battery storage resources in the chart above could be met by "Shimmy DR" resources, which were not modeled explicitly here but may have resource potential up to 300 MW. The timing of the need for short duration services is based on a calculation of load-following reserve requirements outside of RESOLVE. There may be cost benefits to earlier procurement than shown here.

Observations Regarding Air Pollutant Impacts

- The vast majority of electric sector emissions result from CCGTs, because they run more hours of the year.
- New renewables selected by RESOLVE primarily displace CCGT use during daytime hours.
- As the electric sector GHG Planning Target becomes more stringent, new renewables and storage displace more CCGT use outside of daytime hours.
- The largest opportunity to reduce air pollutants from the electric sector is by reducing the use of CCGTs.

GHG Planning Price

- **Recommended GHG Planning Price for IRP 2017-18: $150/MT in 2030**
  - Represents the CAISO system-wide marginal GHG abatement cost associated with achieving the 42 MMT planning target for the electric sector
  - The GHG Planning Price is an outcome of RESOLVE modeling, which constrains GHG emissions at the system level on an annual basis
  - LSEs would use the GHG Planning Price to develop their own portfolios and benchmark against resources in the Reference System Portfolio and an LSE-specific GHG Emissions Benchmark



Staff proposes using a straight line from the current GHG allowance price containment reserve price (~$66/metric ton) to the 2030 GHG Planning Price value

Policy Actions to Implement the Reference System Portfolio

- Staff recommends the Commission take the following near-term policy actions to ensure that IRP guidance informs other proceedings and results in adequate resource procurement to achieve 2030 GHG reduction goals

  1. Consider increasing required renewable procurement
  2. Consider out-of-state (OOS) wind resources
  3. Use the GHG Planning Price in Integrated Distributed Energy Resource (IDER) proceeding
  4. Develop a Common Resource Valuation Methodology (CRVM)
  5. Study natural gas fleet impacts

Role of the Reference System Plan within the Proposed IRP 2017-18 Process

1. **Staff recommends a <u>Reference System Plan</u> reflecting**:
   - A statewide GHG Planning Target of 42 MMT for the electric sector
   - A Reference System Portfolio that achieves the GHG Planning Target and is composed of:
     - baseline resources: 1.5X 2015 Mid AAEE, existing DR, existing gas fleet (minus planned retirements and replacements)
     - new resources: utility-scale solar PV + in-state wind + battery storage/shimmy DR
   - A GHG Planning Price of $150/metric ton in 2030
   - Policy actions to ensure that IRP guidance informs other CPUC proceedings and results in adequate resource procurement
2. **CPUC adopts a <u>Reference System Plan</u>**
3. **LSEs file IRPs that reflect the <u>Reference System Plan</u>**
   - Staff expects that LSE plans will be consistent with three key benchmarks or will provide a justification for any deviation:
     - GHG Planning Price: $150/metric ton in 2030
     - Resources in Reference System Portfolio
     - GHG Emissions Benchmark for individual LSEs
4. **Staff aggregates LSE plans to validate reliability, GHG emissions, and costs**
5. **CPUC decides whether to authorize procurement based on approved, aggregated LSE plans (the <u>Preferred System Plan</u>)**
6. **CPUC considers how to use IRP results to inform other resource-specific proceeding activities**

Schedule of Upcoming Proceeding Activities

Activity	Expected Date
ALJ ruling issues Proposed Reference System Plan	Sept. 19, 2017
Two-day workshop on Proposed Reference System Plan	Sept. 25-26, 2017
Comments due on Proposed Reference System Plan Ruling	Oct. 26, 2017
All-party meeting with Commissioners	Nov. 2, 2017
Reply comments due on Proposed Ref. System Plan Ruling	Nov. 9, 2017
CPUC issues comprehensive IRP Proposed Decision	End of 2017
CPUC transmits guidance to CAISO and CEC for TPP and IEPR purposes for 2018	Early 2018
LSEs file individual Integrated Resource Plans	Q2 of 2018
CPUC adopts or modifies LSE Plans and establishes the Preferred System Plan	End of 2018
CPUC transmits guidance to CAISO and CEC for TPP and IEPR purposes for 2019	Early 2019

1. BACKGROUND

Integrated Resource Planning (IRP) in California Today

- Integrated Resource Planning (IRP) has traditionally been the domain of a single vertically integrated utility
- California today presents a more complex landscape:
  - Multiple Load Serving Entities (LSEs) including utilities, community choice aggregators (CCAs) and competitive retail service providers
  - Multiple state agencies (CPUC, Energy Commission, Air Resources Board) and California Independent System Operator (CAISO)
  - Partially deregulated market
- The value proposition of <u>integrated</u> resource planning is to reduce the cost of achieving GHG reductions and other policy goals by looking across individual LSE boundaries and resource types to identify solutions that might not otherwise be found
- Goal of IRP 2017-18 cycle at CPUC is to ensure that the electric sector is on track to help California reduce economy-wide GHG emissions 40% from 1990 levels by 2030

Statutory Basis of IRP at CPUC

The Commission shall…

PU Code Section 454.51

Identify a diverse and balanced portfolio of resources… that provides optimal integration of renewable energy in a cost-effective manner

PU Code Section 454.52

...adopt a process for each load-serving entity…to file an integrated resource plan…to ensure that load-serving entities do the following…

- Meet statewide GHG emission reduction targets
- Comply with state RPS target
- Ensure just and reasonable rates for customers of electrical corporations
- Minimize impacts on ratepayer bills
- Ensure system and local reliability
- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities
- Enhance distribution system and demand-side energy management
- Minimize air pollutants with early priority on disadvantaged communities

Proposed Two-Year IRP Process

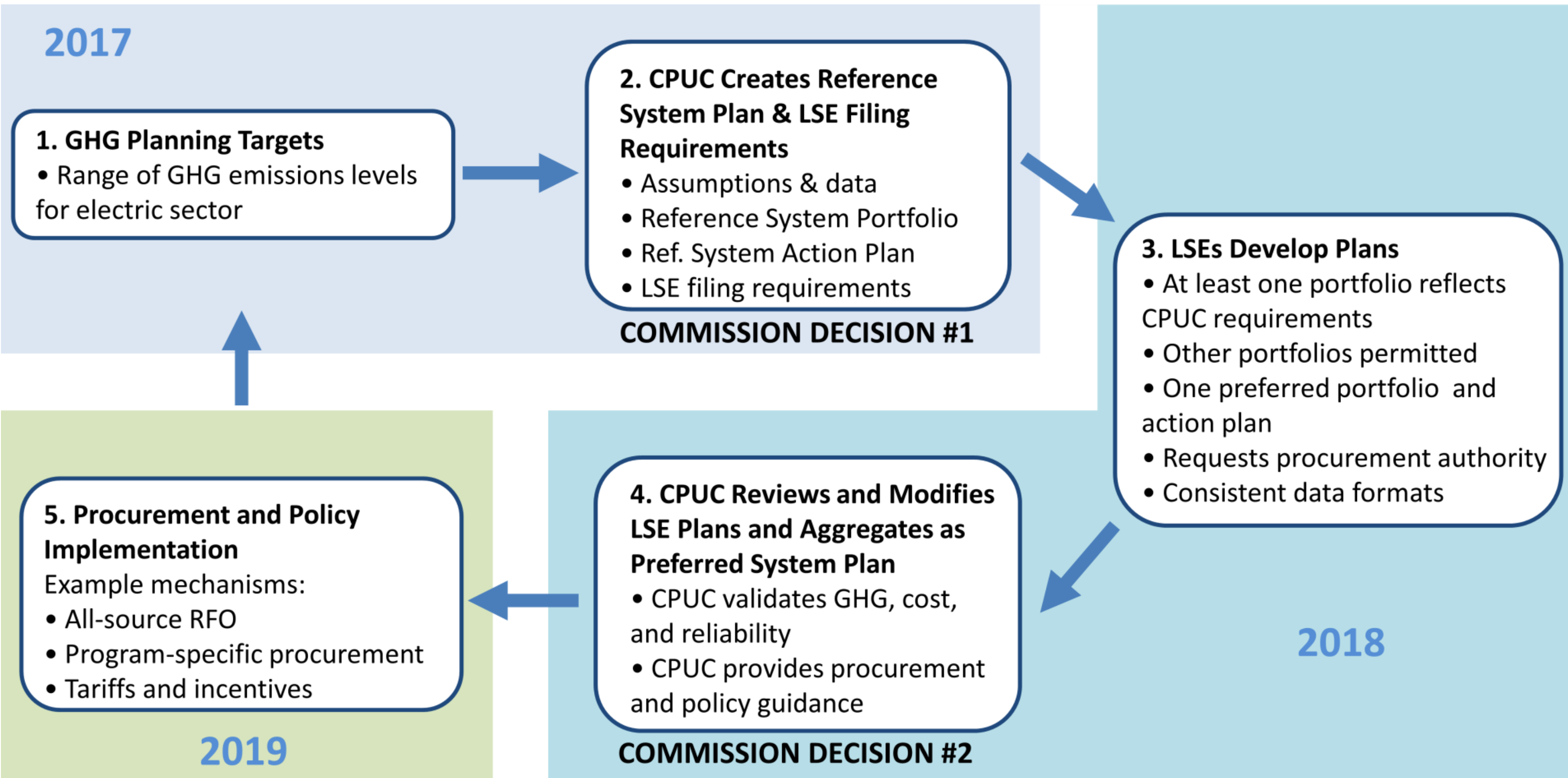
Goals

- Identify solutions that benefit the entire system and accommodate load-serving entity (LSE)-specific constraints and opportunities
- Identify short-term actions (1-3 years) needed to meet long-term goals (10+ years)

Key Steps Include:

- CPUC Develops and Adopts **Reference System Plan** that includes:
  - A GHG Planning Target for the electric sector consistent with the statewide target of 40% below 1990 levels by 2030
  - A Reference System Portfolio of resources that meets GHG target and reliability needs at least cost
  - A GHG Planning Price representing the marginal cost of GHG abatement
  - Commission policy actions to ensure that IRP guidance informs other CPUC proceedings and results in adequate resource procurement
- LSEs Submit Individual Integrated Resource Plans (i.e., LSE Plans)
  - LSEs provide at least one portfolio that uses the GHG Planning Price
  - LSEs identify any procurement needs and request procurement authorization
- CPUC Reviews and Aggregates LSE Plans and Adopts **Preferred System Plan**
  - CPUC aggregates LSEs' preferred portfolios to compare with the Reference System Plan
  - CPUC may authorize procurement, tariff changes, program changes, etc., as needed
  - CPUC provides guidance to other resource proceedings and to CAISO for the TPP and CEC for IEPR

Proposed Two-Year IRP Process



Contents of Reference System Plan

- The Reference System Plan includes four key recommendations:
  - A GHG Planning Target to use for the electric sector in IRP that is consistent with 40% statewide reductions by 2030
  - A Reference System Portfolio – a single portfolio of incremental resources that represents a least-cost, least-risk pathway to achieving the recommended GHG planning target
  - A GHG Planning Price that represents the marginal cost of GHG abatement associated with the Reference System Portfolio and that will enable the CPUC and load-serving entities to consistently value both demand and supply-side resources
  - Near-term Commission policy actions to ensure that the results from IRP modeling inform other CPUC proceedings and lead to the development or procurement of adequate resources

Reference System Plan is Structured Around Three Primary Questions

A. **What resources are needed to reduce GHG emissions in the electric sector?**
B. **What is the optimal portfolio of resources under different, alternative futures?**
C. **What investments, or actions, if any, should be taken in the short term (1-3 years)?**

2. MODELING APPROACH

2.1. MODEL USED

RESOLVE Model Overview

- RESOLVE is a capacity expansion model designed to inform long-term planning questions around renewables integration
- RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting specified GHG targets and other policy goals
- Scope of RESOLVE optimization in IRP 2017-18:
  - Covers the CAISO balancing area including POU load within the CAISO
  - POU resources outside the CAISO balancing area represented as "fixed" quantities that are not subjected to the optimization exercise
  - Does not optimize demand-side resources
  - Optimizes dispatch but not investment outside of the CAISO
- The RESOLVE model used to develop the proposed Reference System Plan, along with accompanying documentation of inputs and assumptions, model operation, and results is available for download from the CPUC's website at: http://cpuc.ca.gov/irp/proposedrsp/

2.2. BASELINE RESOURCES

Defining "Baseline Resources"

- **<u>Baseline resources</u>** are resources that are included in a model run as an assumption rather than being selected by the model as part of an optimal solution
- Within CAISO, the baseline resources are intended to capture:
  - Existing resources, net of planned retirements (e.g. once-through-cooling plants)
  - Future resources that are deemed sufficiently likely to be constructed, usually because of prior CPUC approval
    - e.g. CPUC-approved renewable power purchase agreements, CPUC-approved gas plants
  - Projected achievement of demand-side programs under current policy
    - e.g. forecast of EE achievement, BTM PV adoption under NEM tariff
- In external zones (e.g., BANC), where RESOLVE does not optimize the portfolios, the baseline resources also include projections of resources added to meet policy and reliability goals
- RESOLVE optimizes the selection of additional resources needed to meet policy goals, such as RPS, a GHG target, or a planning reserve margin; these resources that are selected by RESOLVE are *not* baseline resources.
- The same quantity of baseline resources are assumed in the Default, 42 MMT, and 30 MMT Core Cases

Baseline Resource Assumptions

Demand-Side

- **EE:** CEC 2016 IEPR Mid AAEE + AB802 Efficiency (roughly 1.5x gain in EE by 2030)
- **BTM PV:** CEC 2016 IEPR Mid (16 GW by 2030)
- **DR:** Existing DR programs remain in place
- **EVs:** CEC 2016 IEPR Mid
- **Building Electrification:** CEC 2016 IEPR Mid

Supply Side

- **Diablo Canyon Power Plant:** retired in 2024/25
- **Once-Through Cooling (OTC) Plants:** retired according to State Water Board schedule
- **Other Thermal Plants:** remain online throughout modeling
- **Existing Hydro & Pumped Storage:** remain online throughout modeling
- **Storage Mandate:** full storage mandate of 1,325 MW achieved
- **Renewable Resources:** existing and contracted resources remain online

Existing Demand Response Programs in IRP Modeling

- RESOLVE treats the IOUs' existing demand response programs as Baseline Resources; all contribute to meeting the procurement reserve margin of 115%
- Conventional shed DR resources
  - Economically dispatched DR: bid into CAISO market as an economic product (e.g., Capacity Bidding Program)
  - Reliability dispatched DR: bid into CAISO day-ahead and real-time markets as an emergency product (e.g., Base Interruptible Program)
- Time-Varying Rates
  - Included in IEPR demand forecast as a load modifier (e.g., Critical Peak Pricing); peak impact based on 2016 Load Impact Reports*
  - Time-of-Use Rates: default peak impact based on MRW Scenario 4 X 1.5*

*See *RESOLVE Inputs and Assumptions* document for details, available at: http://cpuc.ca.gov/irp/proposedrsp/

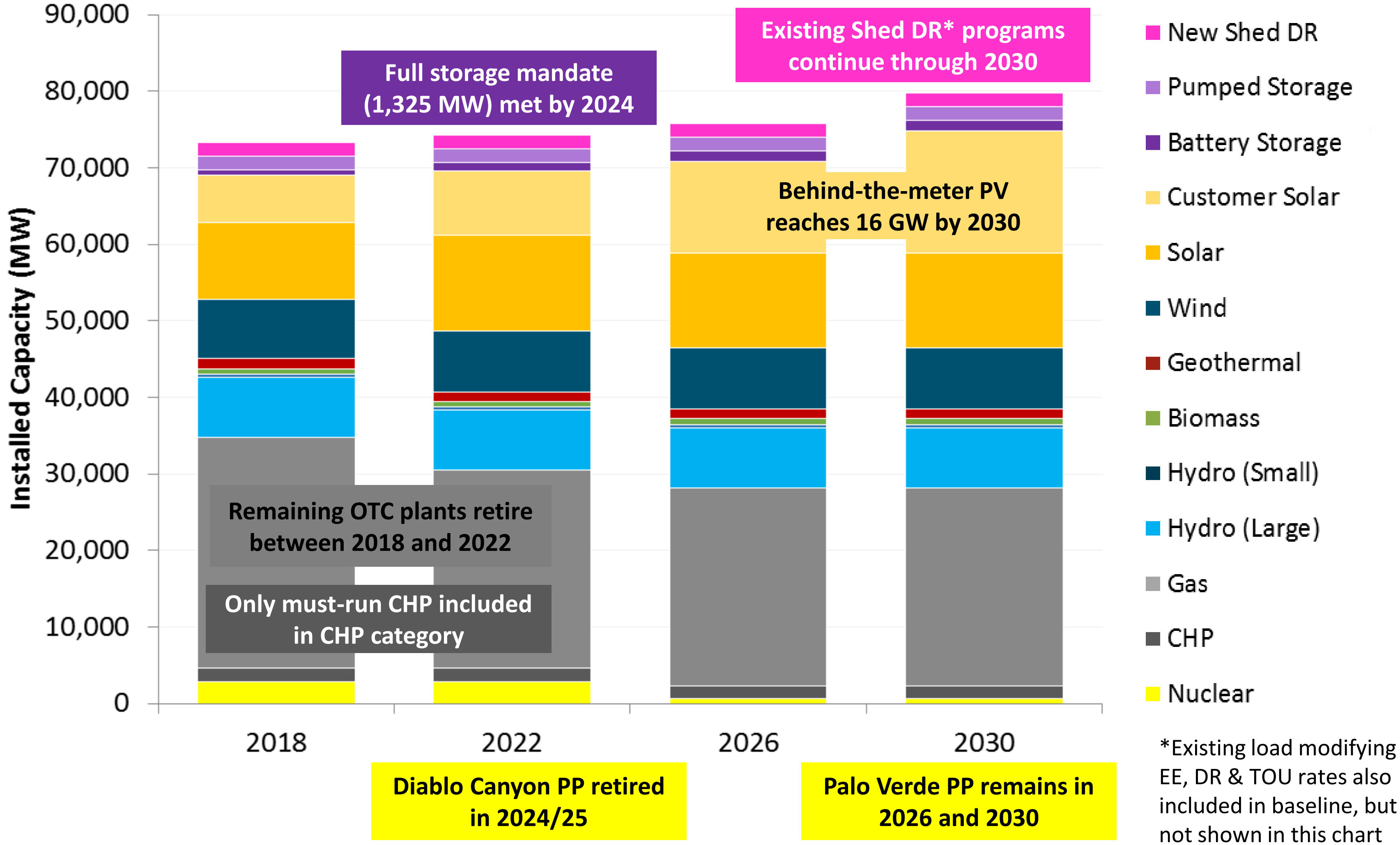
Demand Response Programs as Described in DR Potential Study

DR resources identified in LBNL's final report on the 2025 California DR Potential Study are included in some analyses, with cost, performance, and potential data based on the findings in that report.*

- New "Shed" DR:
  - DR loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events
  - Treated as a candidate resource by RESOLVE in all cases; when selected by the model, the impact of the new shed is incremental to the baseline shed DR from existing programs
- "Shift" DR:
  - DR that encourages the diurnal movement of energy consumption from hours of high demand to hours with surplus renewable generation
  - Not included in RESOLVE core cases due to lack of certainty on viability of resource, but is made available as a candidate resource in the "Shift DR" sensitivity
- "Shimmy" DR
  - DR that provides load-following and regulation type of ancillary services
  - Not included in RESOLVE modeling, but recognized as possible substitute for short-duration storage resources
- "Shape" DR
  - DR that reflects "load-modifying" resources like time-of-use (TOU) and critical peak pricing (CPP) rates, and behavioral DR programs that do not have direct automation tie-ins to load control equipment
  - TOU and existing load-modifying DR (e.g., CPP) included as part of baseline assumptions in RESOLVE modeling, including sensitivities; no addition shape DR was included

*See *RESOLVE Inputs and Assumptions* document for details, available at: http://cpuc.ca.gov/irp/proposedrsp/

Baseline Resources Included in All Cases



*Existing load modifying EE, DR & TOU rates also included in baseline, but not shown in this chart

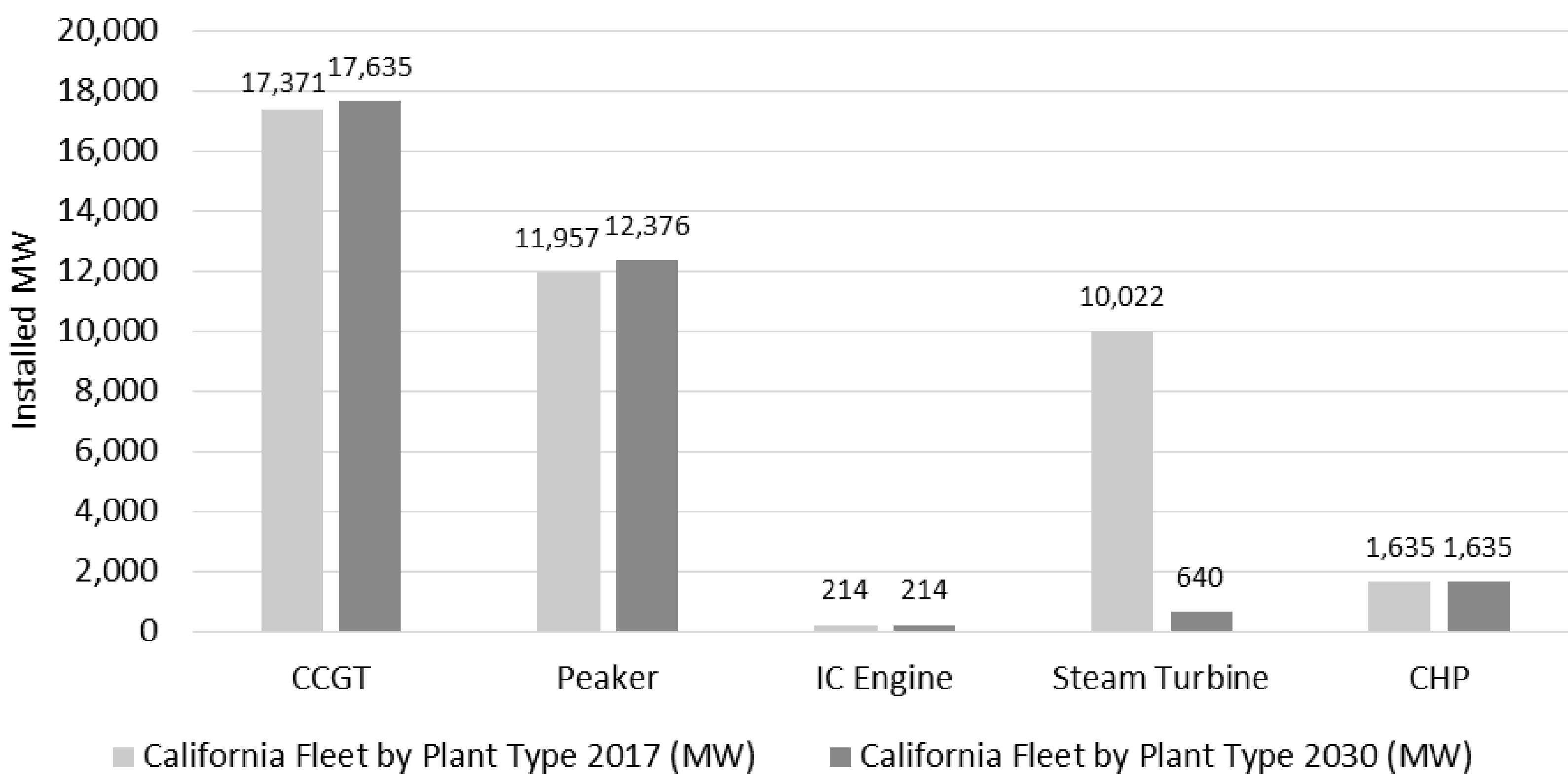
2.3. FOSSIL FLEET IN IRP

IRP Examines the Long-term Evolution of Fossil Fleet, Not Real-Time Dispatch

- Focus of IRP is identifying the short term actions (1-3 years) required to meet long-term policy goals (10-20 years), including reducing GHG emissions and ensuring reliability
- Focus of IRP is not real-time market dispatch dynamics, which determine actual plant performance
- Individual gas plant costs, efficiency, and bidding behavior are difficult to capture in a long-term simulation
- Classes of gas plants tend to exhibit similar market behavior and are therefore aggregated together for the IRP analysis

Natural Gas Fleet Plant Types in California

2017-2030 Comparison



Steam Turbine Retirement Assumptions in IRP Modeling

Plant	Steam Turbine NQC (MW)	Planned Retirement
Alamitos	2,010	2020
Encina	950	2017
Huntington Beach	452	2020
Mandalay	430	2020
Moss Landing	1,509	2017
Ormond	1,516	2020
Pittsburg	1,159	2017
Redondo	1,356	2020
Total	**9,382**	

2.4. CASES MODELED

Cases Modeled

- **Core Policy Cases**: Three cases that reflect different potential GHG trajectories for the electric sector
  - Purpose: Compare the impacts of different GHG goals on portfolio composition, costs, and air pollutants in disadvantaged communities,
- **Core Policy Sensitivities:** Variations on the core policy cases that reflect changes to one or more of the default assumptions about the future (e.g., load, resource costs)
  - Purpose: Determine how different future conditions could affect the impacts of GHG goals
- **Resource Studies:** Variations on the core policy cases and sensitivities that reflect manual addition of certain long-lead time resources
  - Purpose: Evaluate the costs and benefits of near-term procurement of the certain long-lead time, capital-intensive resources and determine whether near-term procurement could lower long-term risk at a reasonable cost

Core Policy Cases

- The three Core Policy Cases reflect procurement reasonably expected to occur based on current policies as well as two different potential electric sector GHG targets:
  - **Default Case:** Reflects existing policies, notably the 50% RPS, which is equivalent to statewide electric sector emissions of ~51 MMT
  - **42* MMT Case:** low end of estimated range for electric sector in CARB scoping plan; reflects scenario in which the state GHG reduction goal is achieved with 40-85 MMT of reductions from <u>unknown</u> measures
  - **30* MMT Case:** electric sector emissions in CARB scenario in which state GHG reduction goal is achieved with <u>known</u> measures

*Alignment with CARB's California Greenhouse Gas Emissions Inventory and Scoping Plan accounting conventions would entail counting emissions for behind-the-meter CHP facilities as electric sector emissions, raising the numbers reported here by ~4 MMT

Translating Statewide GHG Planning Targets to CAISO Targets

- Staff expresses the core modeling cases throughout this analysis in terms of the statewide electric sector GHG planning targets
- However, the CPUC's IRP modeling covers only the CAISO balancing authority area; the RESOLVE model accommodates a GHG planning target that constrains the resource portfolio at the CAISO system level on an annual basis
- For IRP modeling, the CPUC translates the statewide electric sector GHG targets to CAISO targets based on the split in expected emissions from CAISO-balancing area LSEs and non-CAISO balancing area LSEs reflected in CARB's proposed Cap and Trade allowance allocation methodology for 2021-2030
  - Modeling assumes CAISO emissions are ~81% of statewide electric sector total in 2030

Modeling Case	IRP 2030 Statewide Planning Target	2030 CAISO Equivalent Target
Default Case	~51 MMT	41.3 MMT
42 MMT Case	42.0 MMT*	34.0 MMT*
30 MMT case	30.0 MMT*	24.3 MMT*

*Alignment with CARB's California Greenhouse Gas Emissions Inventory and Scoping Plan accounting conventions would entail counting emissions for behind-the-meter CHP facilities as electric sector emissions, raising the numbers reported here by ~4 MMT

Core Policy Sensitivities

Cases that reflect variations in assumptions about the future against which the core policy cases were tested. See Appendix B for descriptions of each case.

- **High EE**
- **Low EE**
- **High BTM PV**
- **Low BTM PV**
- **Flexible EVs**
- **High PV Cost**
- **Low PV Cost**
- **High Battery Cost**
- **Low Battery Cost**
- **No Tax Credits**
- **Gas Retirements**
- **CHP Retirement**
- **Flex Challenged**
- **High Load**
- **High Local Need**
- **Low DR**
- **Low TOU**
- **Mid TOU**
- **Rate Mix 1**
- **Zero Curtailment**
- **High DER**

Resource Studies

- **Resources**: resources manually added* to portfolio **in near term** to test costs and benefits of early procurement
  - OOS Wind (3,000 MW added in 2026)
  - Pumped Storage (1,000 MW added in 2022)
  - Geothermal (1,000 MW added in 2022)
- **Sensitivities**: variations on default assumptions about future conditions tested in each resource study
  - Energy Efficiency Achievement
  - BTM PV Adoption
  - Flexible EVs
  - Building Electrification
  - Solar PV Costs
  - Battery Costs
  - Gas Retirement
  - No Tax Credits

*Note: Pumped storage and geothermal resources were available for selection in all core policy cases and sensitivities; OOS wind on new transmission was not available for selection in the core cases and sensitivities due to uncertainty in the cost and feasibility of the required transmission. For all of the Resource Studies, the resources are manually added rather than simply being available for selection by the model.

Other Studies

- **Several additional discrete studies were conducted to explore specific issues of interest**
  - **Shift DR**: Cases that reflect the potential for shift DR to be deployed to provide grid services (shift DR excluded from rest of cases due to uncertainty about its feasibility and costs)
  - **Post-2030:** Cases run through 2038 that reflect different assumptions about post-2030 load growth due to possible approaches to decarbonizing of other sectors of the economy
  - **Responses to Party Comments**: Cases addressing questions or comments submitted by parties to Staff
    - Short Duration Pumped Storage
    - Unconstrained OOS Wind
    - PTC Extension
    - High Carbon Price
    - Low and High Export Limits

2.5. PORTFOLIO METRICS

Metrics Used to Characterize Modeling Results

- **Selected Resources**, in MW: new resources that the model selects as part of the optimal, least-cost portfolio
- **Costs**
  - Incremental Total Resource Cost: fixed and operating costs, including program costs and customer costs; calculated as difference from Default Case
  - Revenue Requirements: fixed and operating costs, including program costs, but not customer costs
  - Average Rate: revenue requirements divided by retail sales
- **Disadvantaged Community Impacts**
  - Air Pollutants: estimated emissions of NOx and PM2.5 from different classes of gas plants in California
  - Resources in DACs, in MW: same as selected resources, but for resources selected in high-DAC zones

Incremental Total Resource Cost Metric

- The **"incremental total resource cost"** (or incremental TRC) for each scenario is calculated relative to the Default Case
  - Represents an **annualized incremental cost ($MM/yr)** expressed in 2016 dollars over the course of the analysis (2018-2030)
- "Incremental TRC" metric captures the sum of costs directly considered in development of Reference System Plan:
  - RESOLVE objective function
    - Fixed costs of new electric sector investments (generation & transmission)
    - CAISO portion of WECC operating costs (including net purchases & sales)
  - Other costs modeled externally to RESOLVE associated with assumptions
    - Utility & customer demand-side program costs
- "Incremental TRC" does not reflect previously authorized costs
  - e.g., distribution infrastructure replacement
  - These costs also affect rates

Sources for Calculating Revenue Requirements

- Revenue requirements calculated based on
  - RESOLVE outputs
  - IOU IEPR filings: forecasts of annual IOU revenue requirement (2015-2028) submitted to CEC IEPR docket
  - IOU AB67 filings: historical revenue requirement data (2003-2016) submitted by IOUs to CPUC
  - Padilla report: report published by CPUC summarizing cost of renewable procurement
  - Data from demand-side programs: assumed program costs provided by EE, DR groups in Energy Division

Revenue Requirement Components

Category	Component	Source
Distribution	Existing Distribution Revenue Requirement (RR)	IEPR
Transmission	Existing Transmission RR	IEPR
	New Renewables-Driven Transmission	RESOLVE
Generation	Existing Utility Owned Generation (UOG) RR	IEPR
	Existing Bilateral Contracts	AB67
	Existing Renewables Contract Cost	Padilla
	New Renewables Contract Cost	RESOLVE
	New Storage Cost	RESOLVE
	Variable Generation Costs	RESOLVE
	Allowance Allocation Revenue	RESOLVE
Demand-Side Programs	Energy Efficiency Program Costs	Other
	Existing DR Program Costs	Other
	New DR Program Costs	RESOLVE
Other	DWR Bond Charges	IEPR
	Nuclear Decommissioning Cost	IEPR
	Public Purpose *(excluding energy efficiency)*	IEPR
	Other Misc	IEPR

Approach to Analyzing IRP Impact on Localized Air Pollutants in DACs

Statutory Goal for IRP

- "Minimize localized air pollution and other GHG emissions, with early priority on disadvantaged communities"

Analytical Approach

- **Step 1**: Characterize the distribution of power plant classes inside and outside DACs
- **Step 2**: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default, 42 MMT, and 30 MMT
- **Step 3:** Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

Selected Resources in Disadvantaged Communities

Statutory Goal for IRP

- "Strengthen the diversity, sustainability, and resilience … of local communities"

Analytical Goal

- Characterize the amount of new renewable resource selected by the model in disadvantaged communities

Zones Analyzed

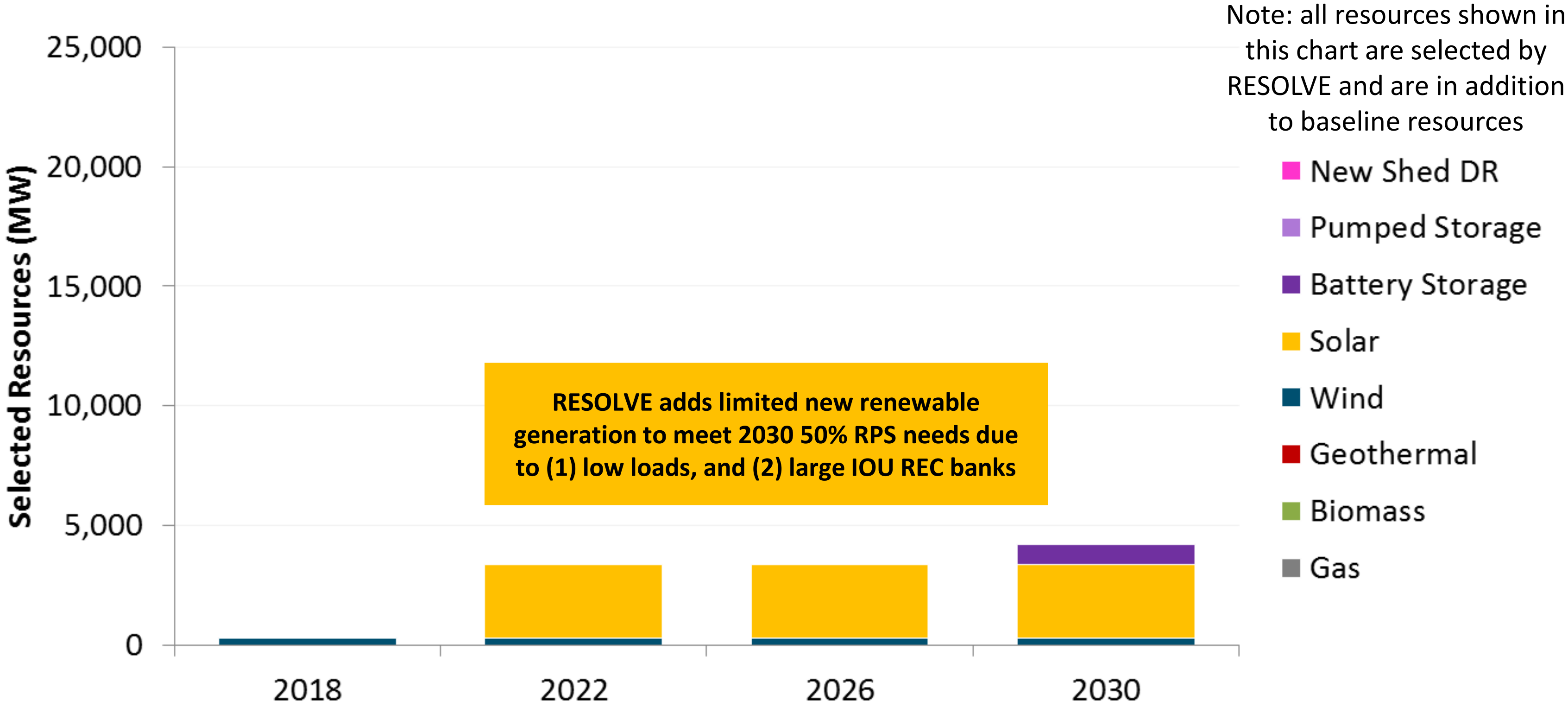
- Renewable resources zones used in RESOLVE are geographic zones that can span multiple counties or substantial portions of counties
- Resource zones originally evolved from Competitive Renewable Energy Zone (CREZ) boundaries
  - Four renewable resource zones in RESOLVE have 25% or more of their population in disadvantaged communities:
    - Central Valley North & Los Banos
    - Westlands
    - Kramer & Inyokern
    - Greater Imperial

3. MODELING RESULTS

3.1. SELECTED RESOURCES IN THE CORE POLICY CASES

RESOLVE Output: Resources Selected in Default Case

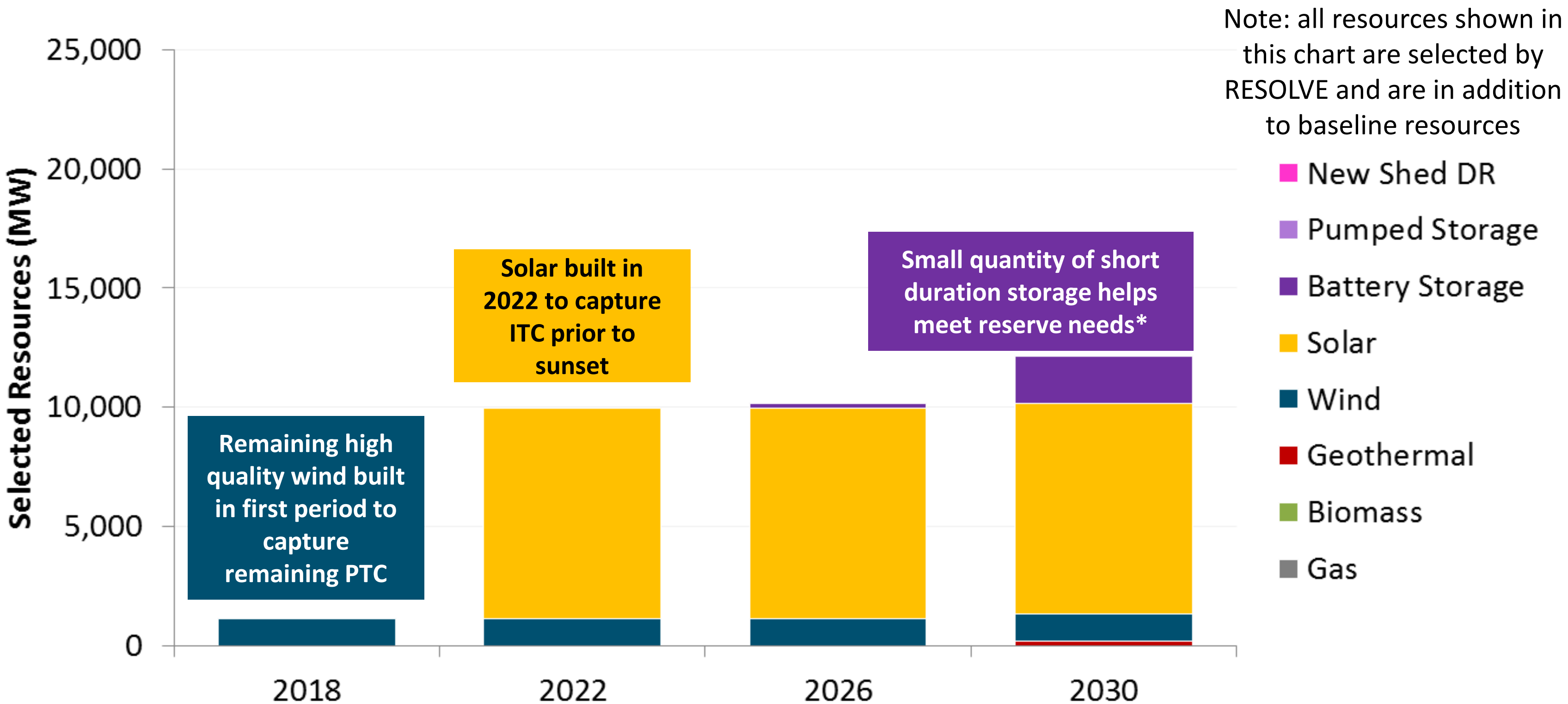
- Model selects ~3 GW of new utility-scale solar by 2030; 300 MW in-state wind; and 800 MW of battery storage in addition to existing/expected baseline of EE, DR, storage, renewables, hydro, gas, and nuclear
- No additional resources needed for balancing (no new gas, pumped storage, or baseload renewables)



Each bar represents the cumulative capacity selected by the model as of the year shown, not the additional capacity added in that year.

RESOLVE Output: Resources Selected in 42 MMT Case

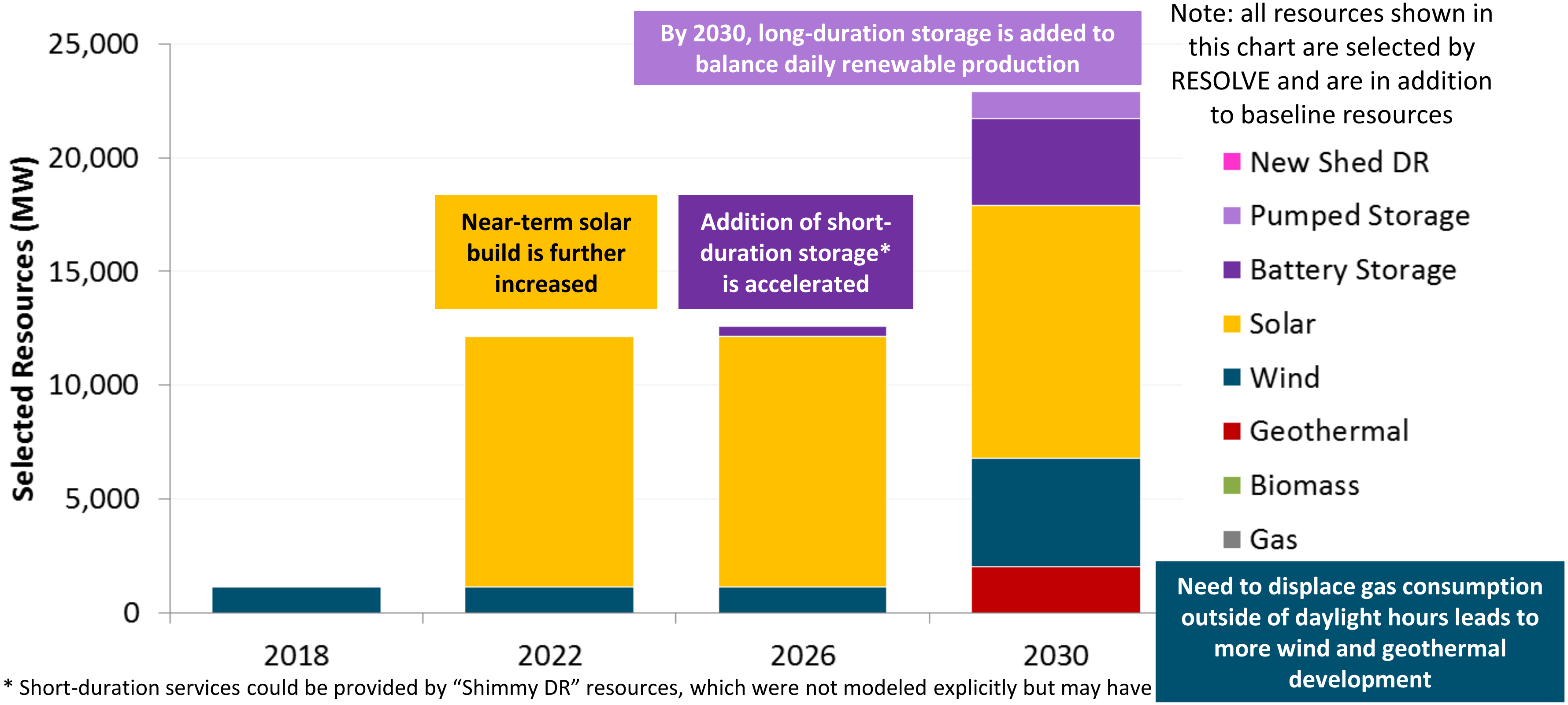
- Model selects ~9 GW of new utility-scale solar; 1,100 MW in-state wind; and 2,000 MW battery storage in addition to expected baseline of EE, DR, storage, renewables, hydro, gas, and nuclear
- Few additional resources needed for balancing (no new gas or pumped storage; 200 MW geothermal)



* Short-duration services could be provided by "Shimmy DR" resources, which were not modeled explicitly but may have resource potential up to 300 MW. The timing of the need for short duration services is based on a calculation of load-following reserve requirements outside of RESOLVE. There may be benefits to earlier procurement than shown here.

RESOLVE Output: Resources Selected in 30 MMT Case

- Model selects ~11 GW of new utility-scale solar; 4,800 MW wind (in-state & OOS); 3,800 MW battery storage, in addition to existing/expected baseline resources
- Model also selects 1,200 MW pumped storage; 2,000 MW geothermal; new gas not needed



* Short-duration services could be provided by "Shimmy DR" resources, which were not modeled explicitly but may have resource potential up to 300 MW. The timing of the need for short duration services is based on a calculation of load-following reserve requirements outside of RESOLVE. There may be benefits to earlier procurement than shown here.

Observations Regarding Selected Resources in Core Policy Cases

- Only utility-scale solar PV and wind are selected in the near term in order to achieve state GHG emission reduction, reliability, and other goals at least cost
  - In the near term, curtailment of solar PV is a lower-cost integration solution than new capital investments in baseload renewables or pumped storage
  - New gas plants are not part of the least-cost solution
  - About 25% of new renewable resources are energy-only, with no resource adequacy value per current rules*
  - All new renewable resources are located in areas that are not expected to require delivery network upgrades*

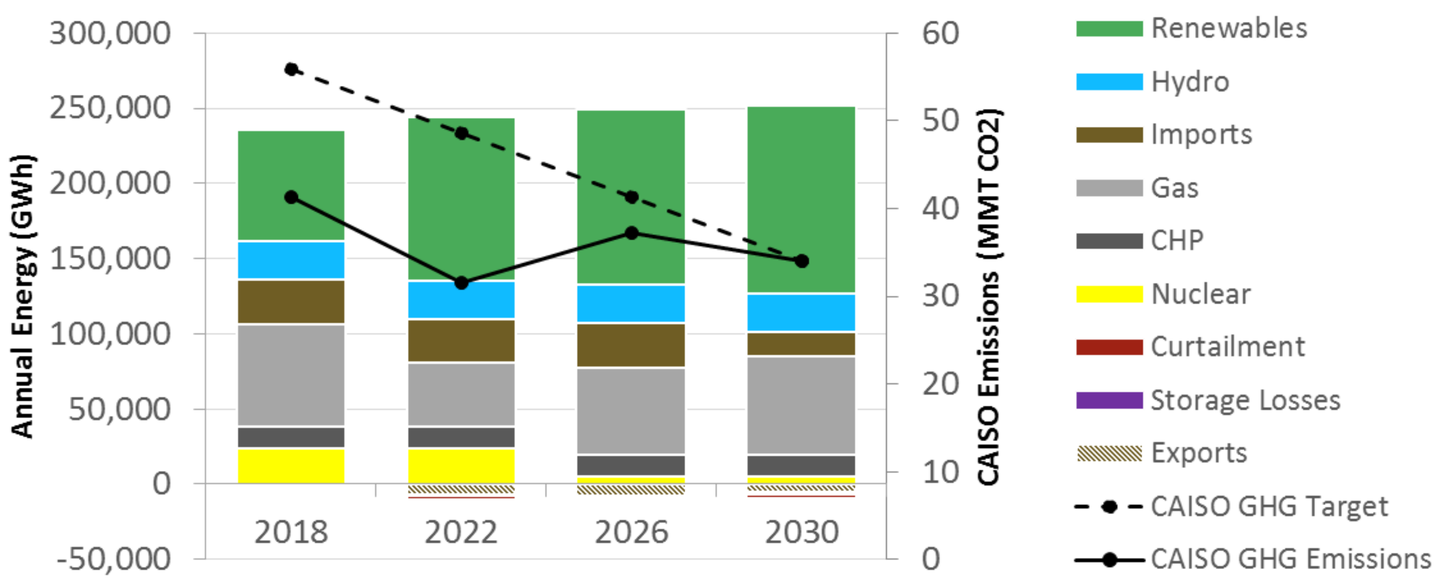
*observed in RESOLVE model output files available online at http://cpuc.ca.gov/irp/proposedrsp/

Effect of Additional Selected Resources on Energy Balance

- The previous slides showed the resources selected by the RESOLVE model to achieve the least cost portfolio that satisfies the specified policy, reliability, and other constraints.
- The following slides show how the electrical energy generated from different resources to serve CAISO load changes in response to the new resources RESOLVE adds to the system

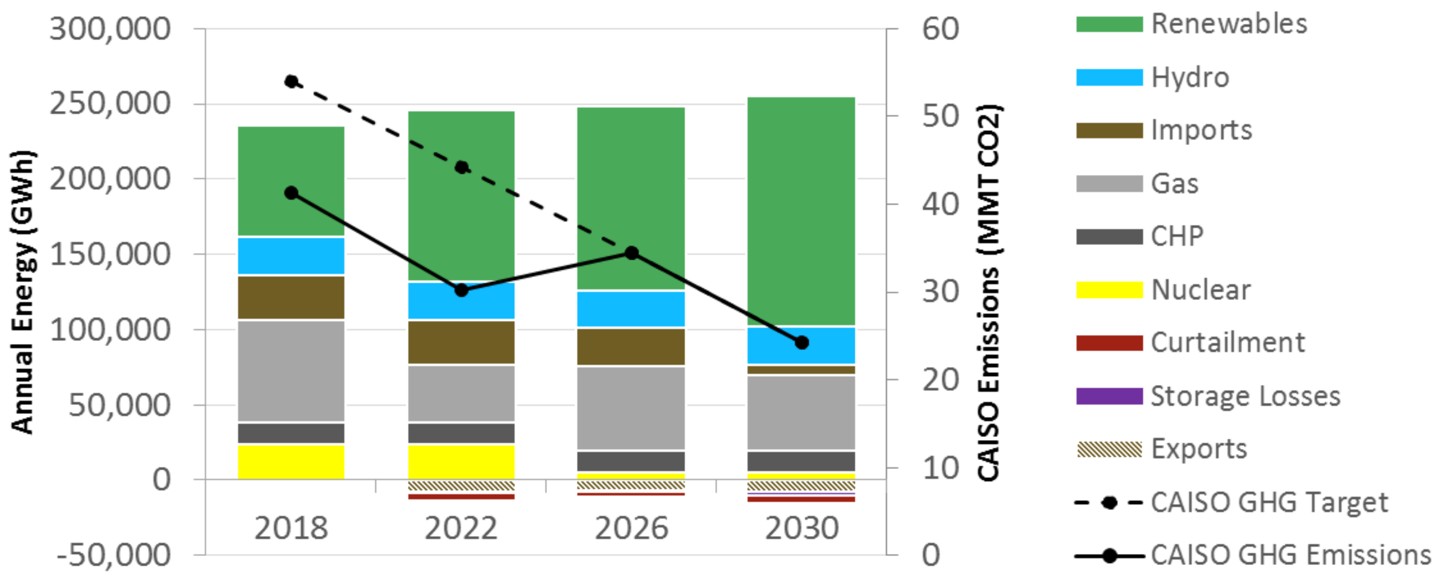
CAISO Energy Balance
42 MMT Statewide Target

- Additional near term renewable build displaces energy from gas and reduces GHG emissions below GHG target in 2018 & 2022
- Energy from gas rebounds by 2026 with Diablo Canyon closure, but imports decrease to meet GHG target by 2030
- RESOLVE results show imports decline relative to in-state gas use because the GHG emissions factor that CARB assigns to imported electricity is larger than California CCGT emission factors



CAISO Energy Balance
30 MMT Statewide Target

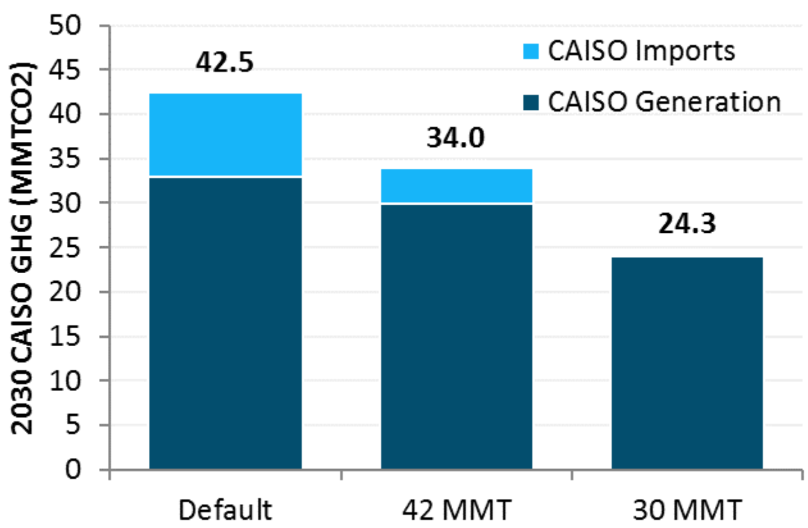
- Additional near term renewable build displaces energy from gas and reduces GHG emissions below GHG target in 2018 & 2022
- Energy from gas rebounds in 2026 with Diablo Canyon closure, but drops again by 2030
- RESOLVE results show imports decline relative to in-state gas use because the GHG emissions factor that CARB assigns to imported electricity is larger than California CCGT emission factors



2030 CAISO Renewables & Emissions

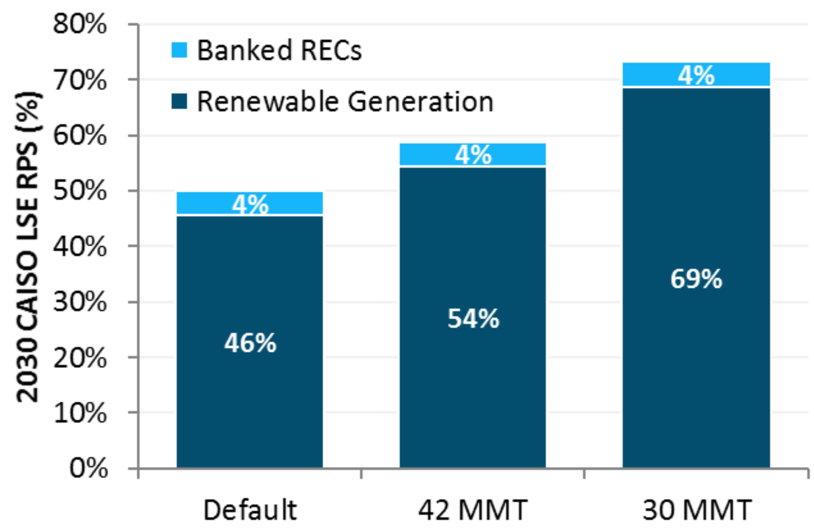
- In the 42 MMT and 30 MMT Cases, the GHG targets drive different RPS achievement levels
- For example, an RPS of ~58% is a byproduct of achieving the 42 MMT carbon goal

Total GHG of CAISO entities in 2030



In GHG-constrained scenarios, imports are reduced significantly due to deemed emissions rate for unspecified imports, which is higher than in-state gas generation

Total RPS% of CAISO entities in 2030



CPUC analysis suggests IOUs' banks may allow them to meet 4% of load with banked RECs

GHG Goals Are Expected to Lead to Reduced Utilization of Fossil Plants

- Gas plants earn revenue when dispatched to serve load and through resource adequacy contracts
- Expansion of the renewable fleet in response to GHG planning targets (42 MMT and 30 MMT) is expected to result in lower utilization rates of certain gas plants relative to the Default Case
- The utilization of gas fleet within California is also affected by the relative GHG intensity of fossil plants outside of California and the deemed rate used by CARB to allocate GHG emissions to imports (0.428 MT/MWh)
  - For example, decreased utilization of out-of-state coal can increase dispatch of in-state gas

Evolution of California's Natural Gas Fleet as Grid Decarbonizes

- RESOLVE does not select new gas in any of the cases studied
- To minimize costs, it might be preferable to selectively retain a subset of existing gas plants rather than build new plants
- This raises the question of which gas plants, or plant attributes, provide value in 2030:
  - Low minimum generation level?
  - Fast ramping ability?
  - Location-specific benefits?
- Determining which gas plants, or plant attributes, offer the most value in future fleet is a complex task and will require additional detailed study in collaboration with the CAISO

3.2. COSTS IN THE CORE POLICY CASES

RESOLVE Output: Incremental Total Resource Cost (TRC) to Meet GHG Targets

- Incremental cost of the optimal portfolios ranges from **$239 to $1,137 million per year** for the 42 MMT and 30 MMT GHG targets, respectively
- Primary driver of incremental costs is **new investment in renewables**, whose zero-carbon generation displaces emissions from thermal generation and imports

		Incremental TRC ($MM/yr)	
		42 MMT	30 MMT
Incremental Fixed Costs	*Renewables*	+$843	+$2,203
	Storage	+$45	+$400
	Thermal	—	—
	DR	—	—
	Transmission	—	+$41
Incremental Variable Costs		-$650	-$1,507
Incremental DSM Program Costs		—	—
Incremental Customer Costs		—	—
Incremental Total Resource Cost		**+$239**	**+$1,137**

Increased investment in zero-carbon renewables is primary driver of incremental costs

No additional thermal or DR resources added to meet GHG goals

Little to no new transmission construction

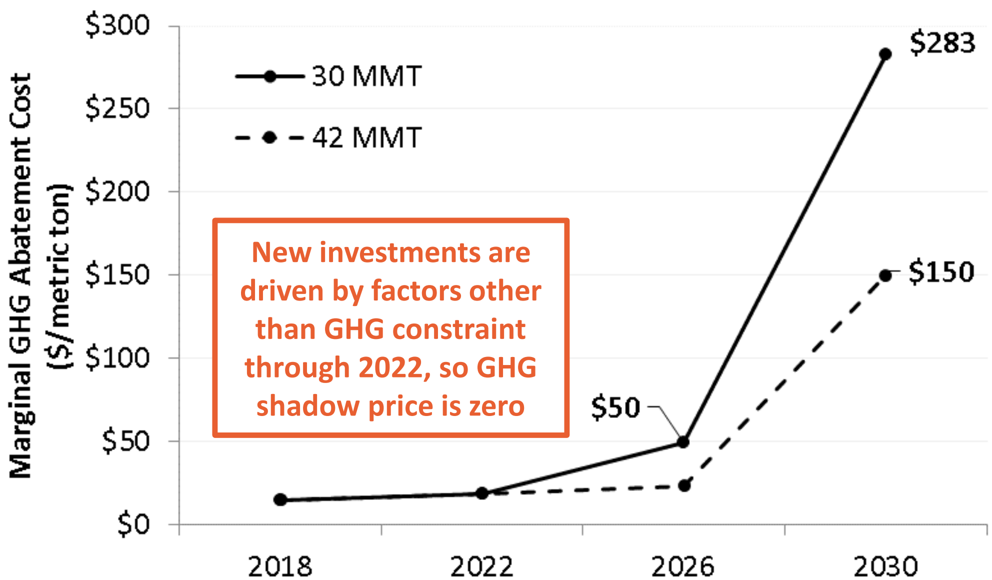
Addition of renewables displaces generation from thermal resources, reducing operating costs

Because demand-side assumptions are constant between scenarios, incremental costs are zero

GHG Planning Price

- Staff defines the "GHG Planning Price" as the system-wide marginal GHG abatement cost associated with achieving the electric sector 2030 GHG Panning Target
- To determine the GHG Planning Price, Staff relies on the "shadow price" of the GHG constraint in RESOLVE
  – Within optimization modeling, the "shadow price" of a constraint is the change in the objective function if that constraint is relaxed by one unit and is frequently interpreted as the marginal cost to meet that constraint
- Because RESOLVE captures the financial cost of allowances under the cap & trade in its objective function, the shadow price alone does not reflect the full marginal cost of GHG abatement
  – An increase in the assumed allowance cost increases the cost to combust fossil fuels, reducing the apparent cost premium of carbon-free resources (and, by extension, the shadow price)
- Therefore, Staff calculates the GHG Planning Price as the sum of RESOLVE's GHG shadow price and the assumed cost of allowances under cap & trade

RESOLVE Output: Marginal GHG Abatement Cost 42 MMT & 30 MMT Cases



In 30 MMT case, GHG constraint first becomes the main driver of new investments in 2026, and marginal cost of carbon abatement increases quickly thereafter as marginal GHG reductions become more expensive

In 42 MMT case, GHG constraint does not become the main driver of new investments until 2030

- Exponential shape of GHG abatement cost curve reflects the selection of increasingly higher-cost resources to reduce increasingly more GHG emissions
- The total marginal cost of GHG abatement (or "GHG Planning Price") is estimated by adding the assumed allowance cost to the GHG shadow price
  - 2030 marginal abatement cost in 30 MMT scenario: $254 + $29 = **$283/metric ton** (rounded up)
  - 2030 marginal abatement cost in 42 MMT scenario: $121 + $29 = **$150/metric ton**

RESOLVE Output: Revenue Requirements

- 2030 revenue requirements are based on sources shown in previous slides
- Costs other than IRP projected to increase revenue requirements by 11% (real) over 2018-2030, driven largely by distribution and transmission costs
- By 2030 IRP adds 1% (real) to revenue requirements in 42 MMT Case and 6% in 30 MMT Case, mostly due to fixed costs of renewable energy

Category*	Annual Revenue Requirement ($MM/yr)				Change from 2018 ($MM/yr)		
	Default 2018	Default 2030	42 MMT 2030	30 MMT 2030	Default 2030	42 MMT 2030	30 MMT 2030
Distribution	$11,443	$13,818	$13,818	$13,818	+$2,375	+$2,375	+$2,375
Transmission	$3,903	$4,746	$4,746	$4,829	+$843	+$843	+$926
Generation (Conventional)	$10,496	$10,705	$9,923	$8,337	+$107	-$516	-$2,051
Generation (Renewable)	$7,585	$8,609	$9,621	$12,126	+$1,024	+$2,036	+$4,541
Generation (Storage)	$256	$464	$551	$1,254	+$208	+$295	+$999
DSM Programs	$1,649	$1,984	$1,984	$1,984	+$336	+$336	+$336
Other	$1,081	$506	$506	$506	-$575	-$575	-$575
Total	**$36,412**	**$40,832**	**$41,150**	**$42,854**	**+$4,420**	**+$4,738**	**+$6,442**

*See section 2.5 for breakdown of categories and source of data

RESOLVE Output: Average Retail Rate

- Average retail rates calculated as revenue requirements divided by sales
- Costs other than IRP projected to increase average retail rate 17% (real) over 2018-2030, driven largely by distribution and transmission costs
- By 2030 IRP adds 1% (real) to rates in 42 MMT case, and 6% in 30 MMT Case, mostly due to fixed costs of renewable energy

Category	Average Retail Rate (c/kWh)				Change from 2018 (c/kWh)		
	Default 2018	Default 2030	42 MMT 2030	30 MMT 2030	Default 2030	42 MMT 2030	30 MMT 2030
Distribution	5.5	7.0	7.0	7.0	+1.5	+1.5	+1.5
Transmission	1.9	2.4	2.4	2.4	+0.5	+0.5	+0.6
Generation (Conventional)	5.1	5.4	5.0	4.2	+0.4	-0.0	-0.8
Generation (Renewable)	3.7	4.4	4.9	6.1	+0.7	+1.2	+2.5
Generation (Storage)	0.1	0.2	0.3	0.6	+0.1	+0.2	+0.5
DSM Programs	0.8	1.0	1.0	1.0	+0.2	+0.2	+0.2
Other	0.5	0.3	0.3	0.3	-0.3	-0.3	-0.3
Total	**17.5**	**20.6**	**20.8**	**21.7**	**+3.1**	**+3.3**	**+4.1**

Observations Regarding Costs in Core Policy Cases

- Distribution and transmission costs not related to GHG targets are projected to drive increases revenue requirements, average rates, and bills over the period 2018-2030
- Costs resulting from new renewable energy to reduce GHG emissions are projected to have a smaller incremental impact on revenue requirements, rates, and bills over the same period
- In order to minimize ratepayer bills and ensure just and reasonable rates while achieving the state's GHG emissions reduction and other goals, it is important to identify opportunities to put downward pressure on costs

Summary Metrics for 42 MMT and 30 MMT Portfolios in 2030

Metric	42 MMT Case	30 MMT Case
CAISO GHGs	**34 MMT**	**24 MMT**
Selected Resources	• **9,000 MW solar PV** • **1,000 MW wind** • **200 MW geothermal** • **2,000 MW battery storage**	• **11,000 MW solar PV** • **4,800 MW wind** • **2,000 MW geothermal** • **3,800 MW battery storage** • **1,200 MW pumped storage**
Selected In-State Renewables	**7,200 MW**	**13,000 MW**
Levelized Total Resource Cost (TRC)	**$40.0 billion/year**	**$40.9 billion/year**
Incremental TRC *(relative to Default Case)**	***$239 million/year****	***$1.1 billion/year****
Marginal GHG Abatement Cost	**$150/metric ton**	**$283/metric ton**
System Planning Reserve Margin (resulting from addition of new resources)	**31%**	**42%**

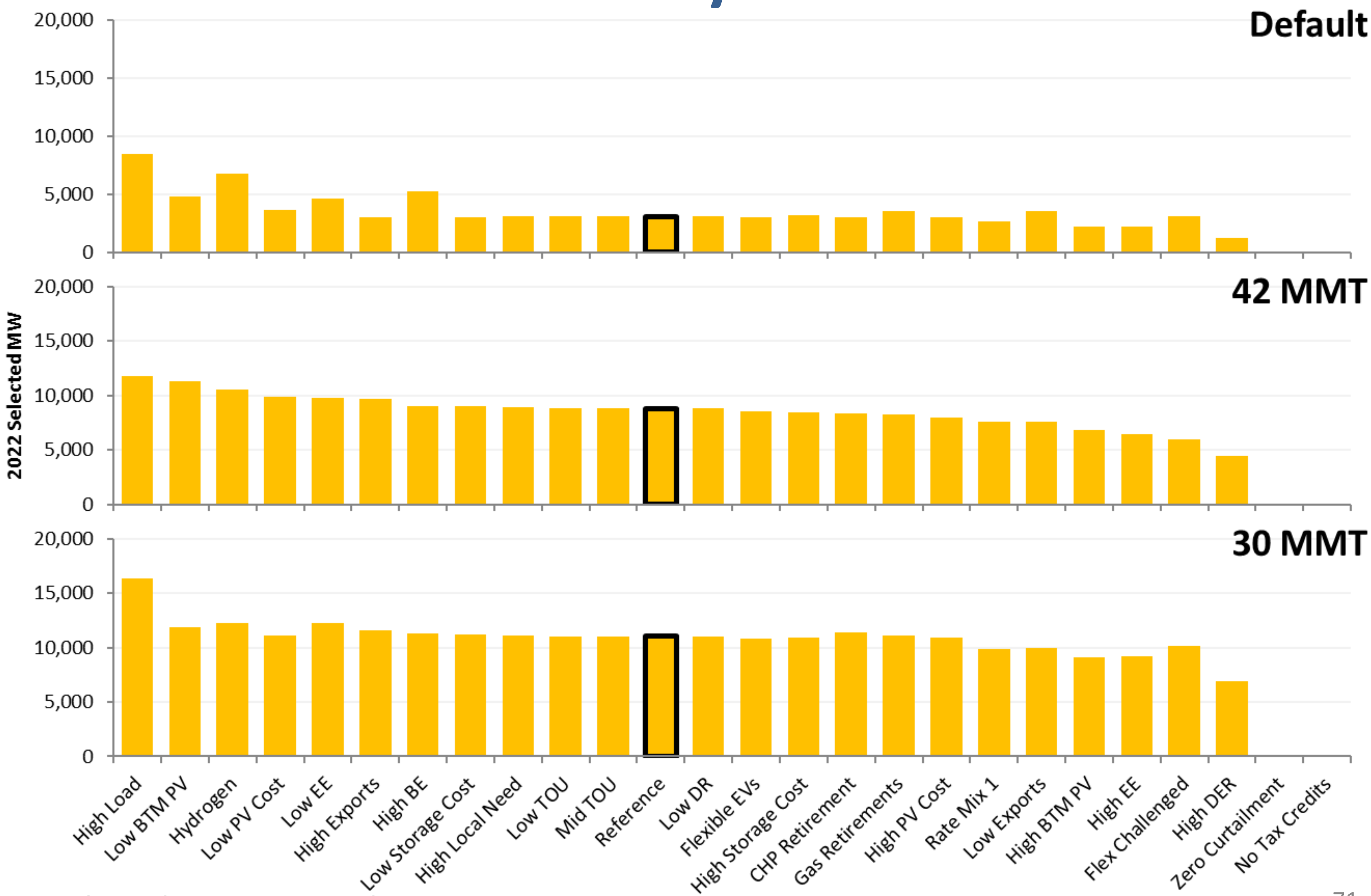
*The incremental TRC results are calculated relative to the Default Case. All other results are total, not incremental.

3.3. SELECTED RESOURCES AND COSTS IN THE SENSITIVITY CASES

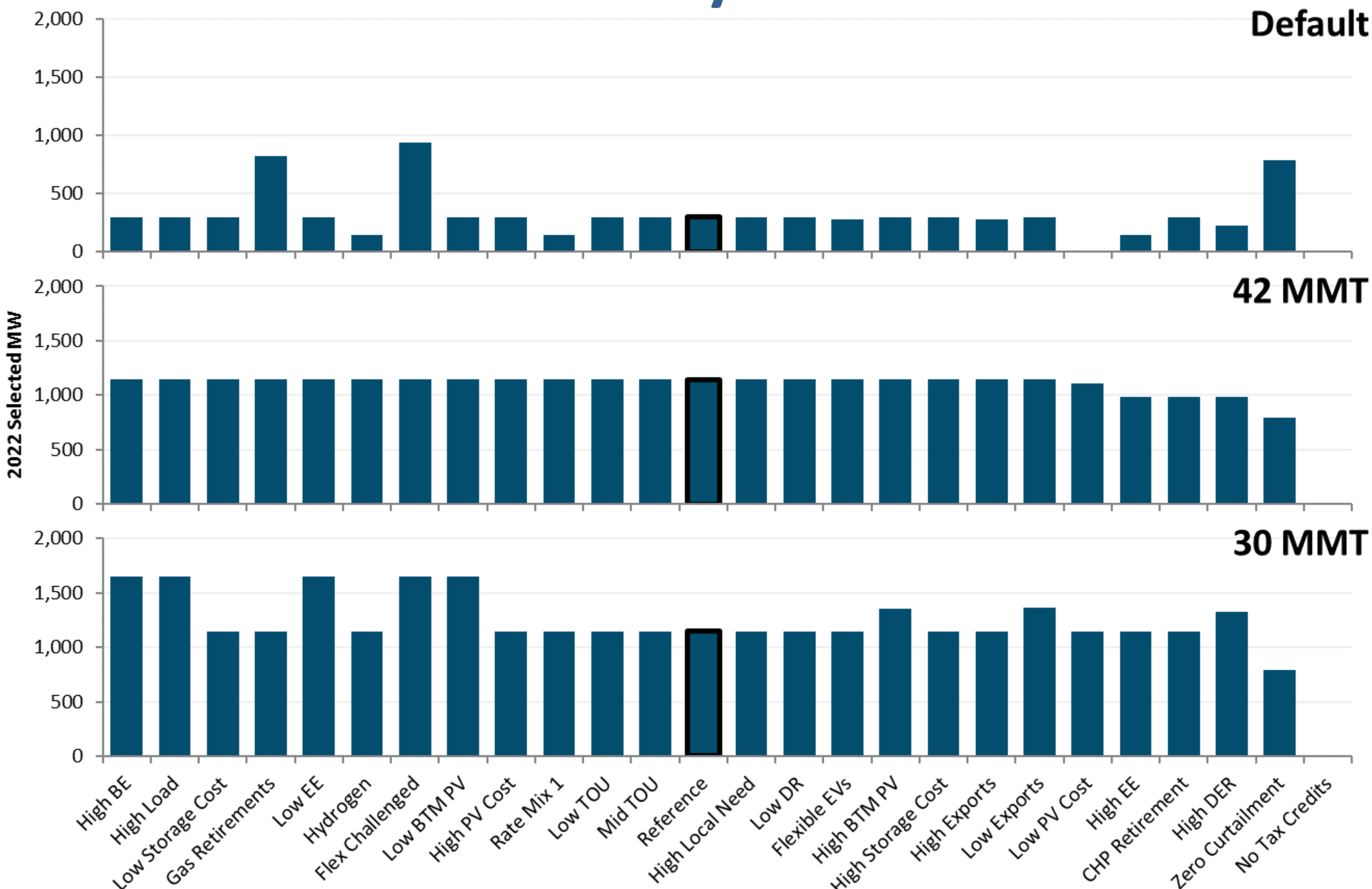
Guide to Organization of Sensitivity Results

- The slides in this subsection present information on:
  - how the quantities of four different types of resources (solar PV, wind, geothermal, and pumped storage) that were selected in the Core Policy Cases change under different assumptions about the future
  - the impacts of those changes on incremental total resource cost
- The information on quantities of selected resources are presented in charts followed by a summary of the results
  - For solar PV and wind, results are shown for the year 2022, since the Core Policy Cases show these resources being selected relatively early in the planning horizon
  - For geothermal and pumped storage, results are shown for the year 2030, since the Core Policy Cases indicated that these resources were selected relatively late in the planning horizon
- Changes in incremental total resource cost are shown in tables at the end of the subsection
- See Appendix B for more detail on how the sensitivity cases were defined

RESOLVE Output: Solar PV Selected in 2022 in Sensitivity Cases



RESOLVE Output: Wind Selected in 2022 in Sensitivity Cases



Explanation of Solar PV and Wind Results

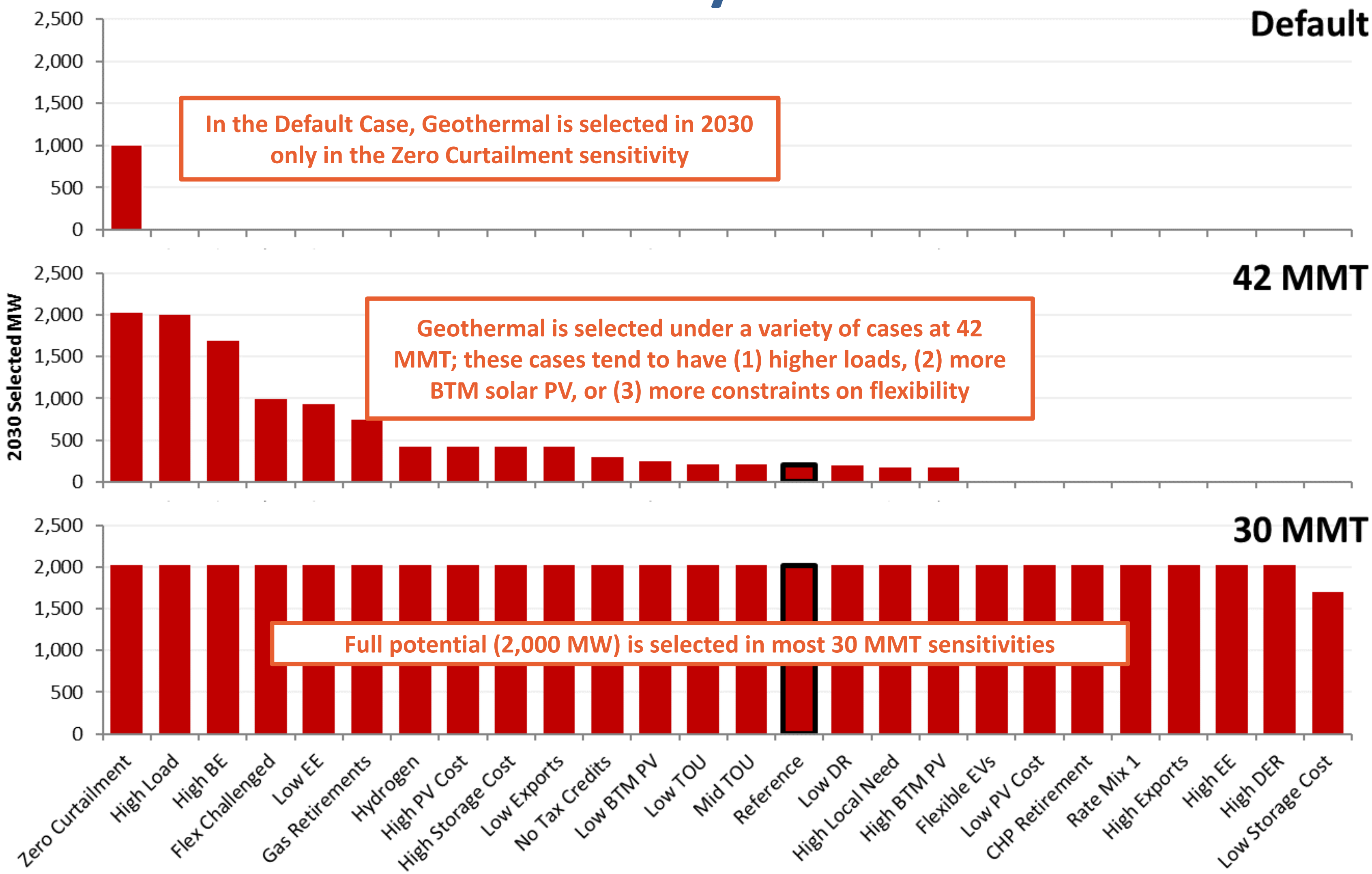
Default Cases

- Solar PV and wind are selected in almost every case

42 MMT Cases

- Solar PV and wind are selected in almost every case
- The amount of solar PV and wind selected is larger and more constant across the 42 MMT cases than across the Default cases (the 42 MMT sensitivities generally select approximately 9,000 MW of solar PV and 1,000 MW of wind).
- **30 MMT Cases**
- Solar PV and wind are selected in almost every case
- The amount of solar PV selected is even larger across most cases than under the 42 MMT case (generally above 10,000 MW)

RESOLVE Output: Geothermal in 2030 in Sensitivity Cases



Explanation of Geothermal Results

Default Case

- Geothermal is only selected in the "Zero Curtailment" sensitivity, as few renewable resources must be added to comply with existing renewable energy mandates

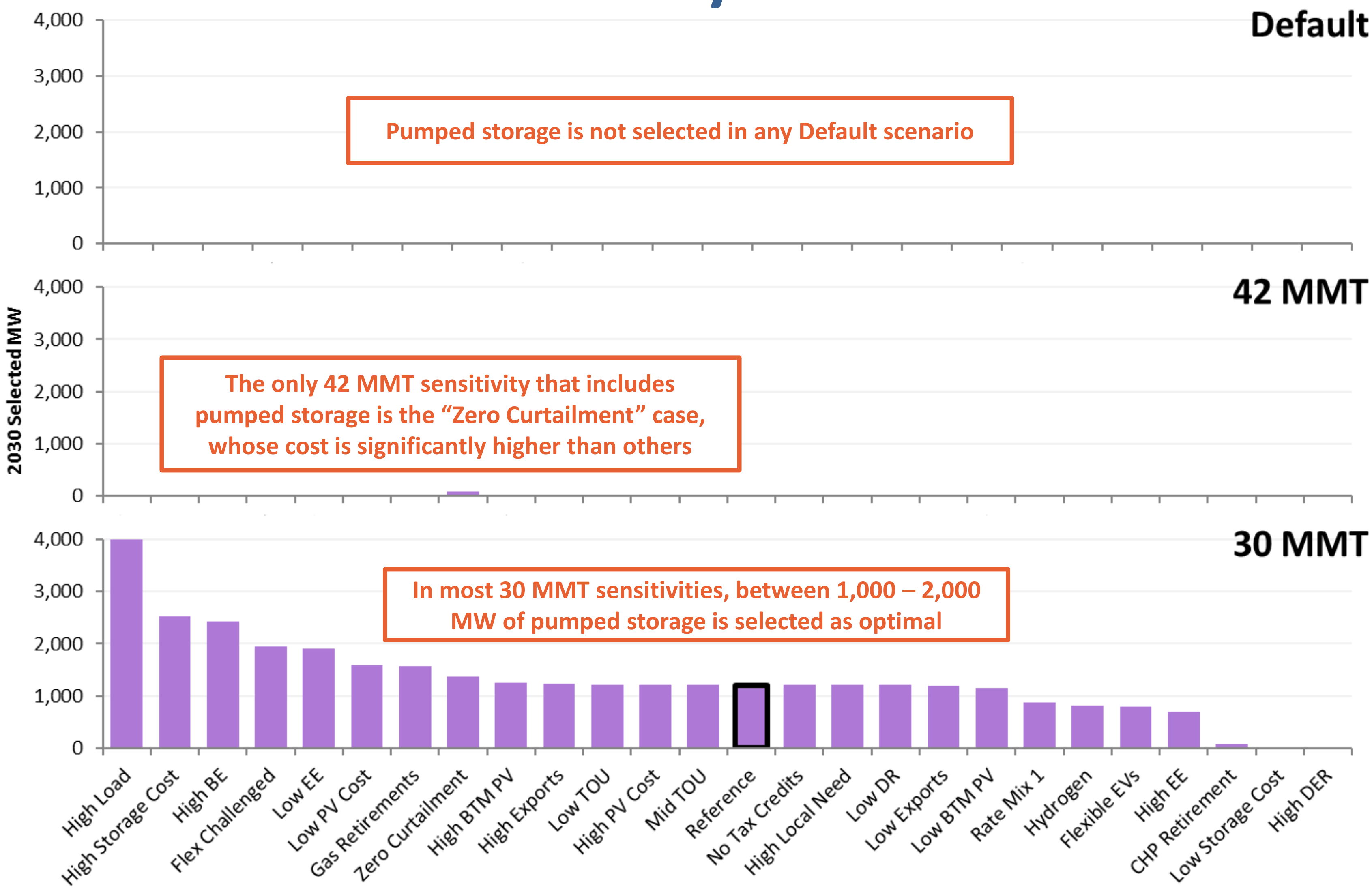
42 MMT Case

- Geothermal resources are selected under a select set of sensitivities:
  - When capacity is needed to meet planning reserve margin (e.g. under "Gas Retirements" sensitivity)
  - When higher loads exist and incremental need for renewables creates more value for diversity (e.g. under "Low EE," "High Building Electrification," and "High Load" sensitivities)
  - When there are limitations on operational flexibility (e.g. under "Flexibility Challenged" sensitivity)

30 MMT Case

- Maximum in-state geothermal potential is selected across all sensitivities

RESOLVE Output: Pumped Storage in 2030 in Sensitivity Cases



3.6. Selected Resource Studies

Explanation of Pumped Storage Results

- Main driver of pumped storage in the portfolio is the benefit of capturing GHG-free energy produced in-state
- Under Default and 42 MMT Cases, renewable integration challenges are not significant enough to justify addition of long-duration storage
  - Renewable curtailment offers a lower cost solution to manage oversupply
- Some amount of pumped storage is selected in all 30 MMT sensitivities, and most include at least 2,000 MW
- Factors that increase the amount of more pumped storage additions in 30 MMT Case:
  - Increased capacity needed to meet planning reserve margin (PRM) (e.g. under "Gas Retirements" sensitivity)
  - Higher loads, which must be met by incremental solar + long-duration storage (e.g. under "Low EE," "High Building Electrification," and "High Load" sensitivities)
  - Limitations on operational flexibility (e.g. under "Flexibility Challenged" sensitivity)

RESOLVE Output: Impact of Sensitivities on Incremental Cost (1/2)

All costs shown relative to Default Reference case

Sensitivity	Incremental TRC ($MM/yr)			Change from Reference ($MM/yr)		
	Default	42 MMT	30 MMT	Default	42 MMT	30 MMT
Reference	**$0**	**$239**	**$1,137**			
High EE	$120	$271	$1,048	+$120	+$33	-$89
Low EE	-$87	$282	$1,331	-$87	+$43	+$193
High BTM PV	$471	$677	$1,577	+$471	+$438	+$440
Low BTM PV	-$734	-$444	$480	-$734	-$682	-$657
Flexible EVs	-$66	$132	$935	-$66	-$107	-$202
High PV Cost	$240	$510	$1,419	+$240	+$271	+$282
Low PV Cost	-$280	-$137	$730	-$280	-$376	-$407
High Battery Cost	$264	$532	$1,470	+$264	+$294	+$333
Low Battery Cost	-$218	-$9	$617	-$218	-$248	-$521
No Tax Credits	$69	$382	$1,391	+$69	+$143	+$253
Gas Retirements	$351	$480	$1,233	+$351	+$241	+$96

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

RESOLVE Output: Impact of Sensitivities on Incremental Cost (2/2)

All costs shown relative to Default Reference case

Sensitivity	Incremental Cost ($MM/yr)			Change from Reference ($MM/yr)		
	Default	42 MMT	30 MMT	Default	42 MMT	30 MMT
Reference	**$0**	**$239**	**$1,137**			
CHP Retirement	-$82	$75	$762	**-$82**	**-$163**	**-$376**
Flex Challenged	$68	$398	$1,459	**+$68**	**+$159**	**+$322**
High Load	-$388	$322	$1,697	**-$388**	**+$84**	**+$560**
High Local Need	$33	$270	$1,161	**+$33**	**+$31**	**+$24**
Low DR	-$35	$204	$1,103	**-$35**	**-$35**	**-$35**
Low TOU	$7	$246	$1,144	**+$7**	**+$8**	**+$7**
Mid TOU	$4	$242	$1,141	**+$4**	**+$4**	**+$3**
Rate Mix 1	-$204	-$17	$818	**-$204**	**-$255**	**-$319**
Zero Curtailment	$826	$1,348	$2,902	**+$826**	**+$1,109**	**+$1,764**
High DER	$610	$740	$1,435	**+$610**	**+$502**	**+$297**

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

Observations Regarding Sensitivity Cases

- With some exceptions, the least-cost portfolio composition for meeting different GHG targets and reliability constraints does not change much under different assumptions about the future
- Generally, model results indicate that utility-scale solar PV and wind procured within next 1-3 years to take advantage of federal tax credits are part of least-cost solution for 2030
- Modeled future conditions that tend to increase total resource costs: high levels of BTM PV, zero curtailment (requires 20,000 MW of additional battery storage in 42 MMT case), no tax credits, gas retirement, high loads, high technology costs

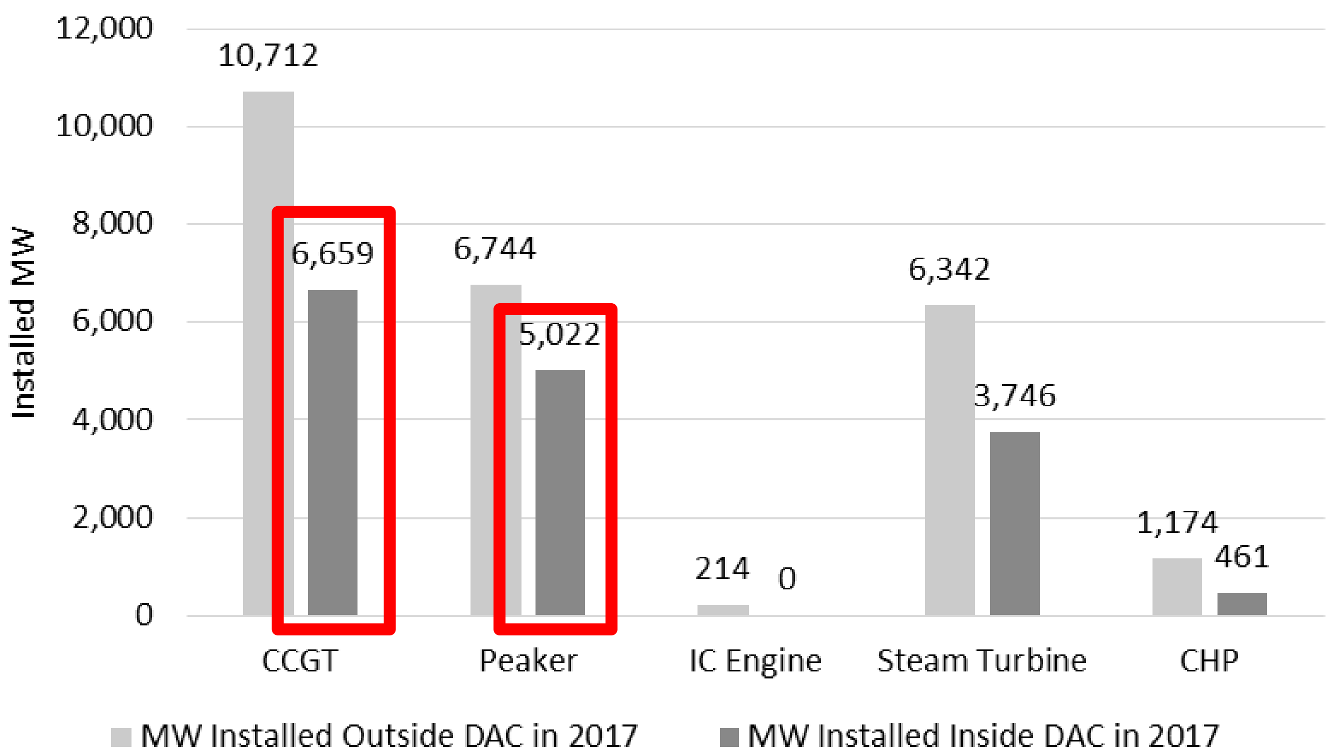
3.4. AIR POLLUTANTS STATEWIDE

Guide to Organization of Air Pollutant Results

- This subsection presents information on
  - The distribution of the primary classes of gas plants in California with respect to the locations of disadvantaged communities
  - The projected change in gas use in different classes of gas plants between 2018-2030 under the three Core Policy Cases
  - The estimated quantity of air pollutants in 2030 from the two classes of California gas plants most prevalent in disadvantaged communities under different assumptions about future conditions (for more information about how the sensitivities are defined, see Appendix B)
  - The relative contribution of electric utilities and other sources to air pollutant emissions, according to CARB data
- The information is presented in sequence listed above
- For more detailed information on how the study of air pollutants was designed, see Appendix A

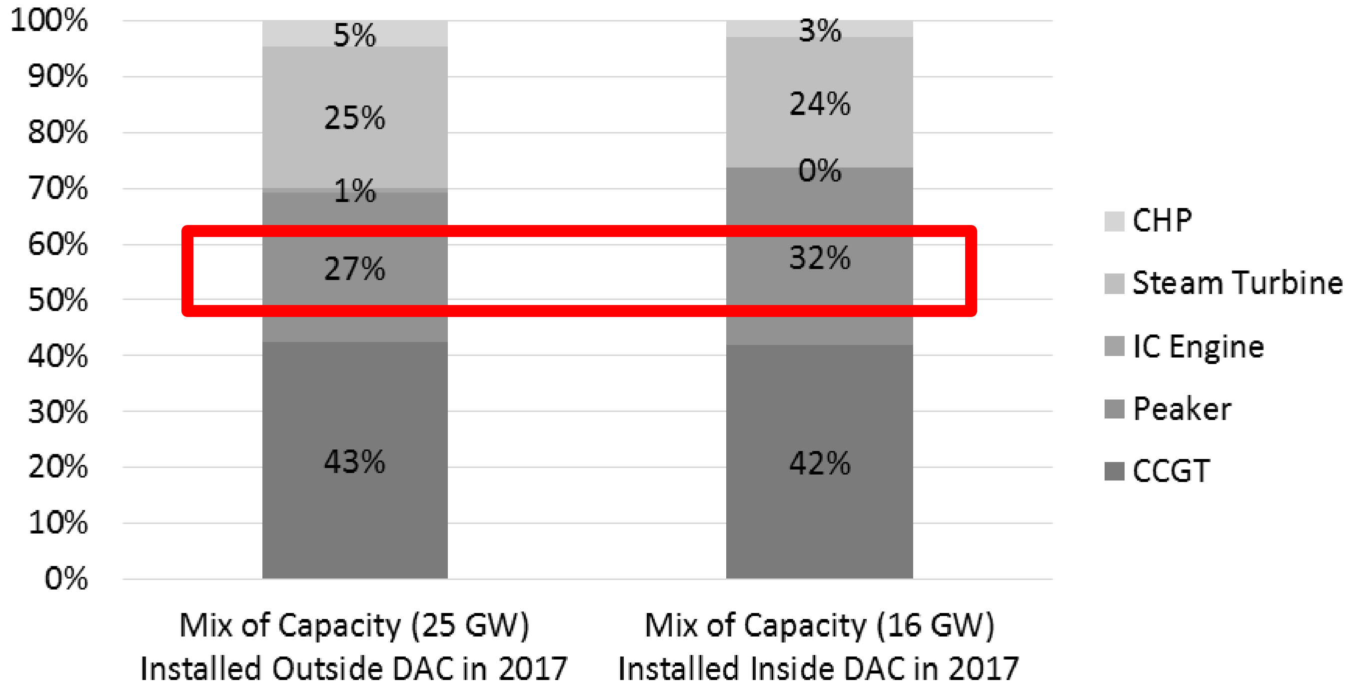
Absolute Frequency Distribution of 2017 Fossil Capacity in California By Power Plant Type

- The most common plants in DACs by capacity are CCGTs and Peakers
- Reductions from these plants may have the greatest absolute impacts on localized air pollutants from the electric sector



Relative Frequency Distribution of 2017 Fossil Capacity in California by Power Plant Type

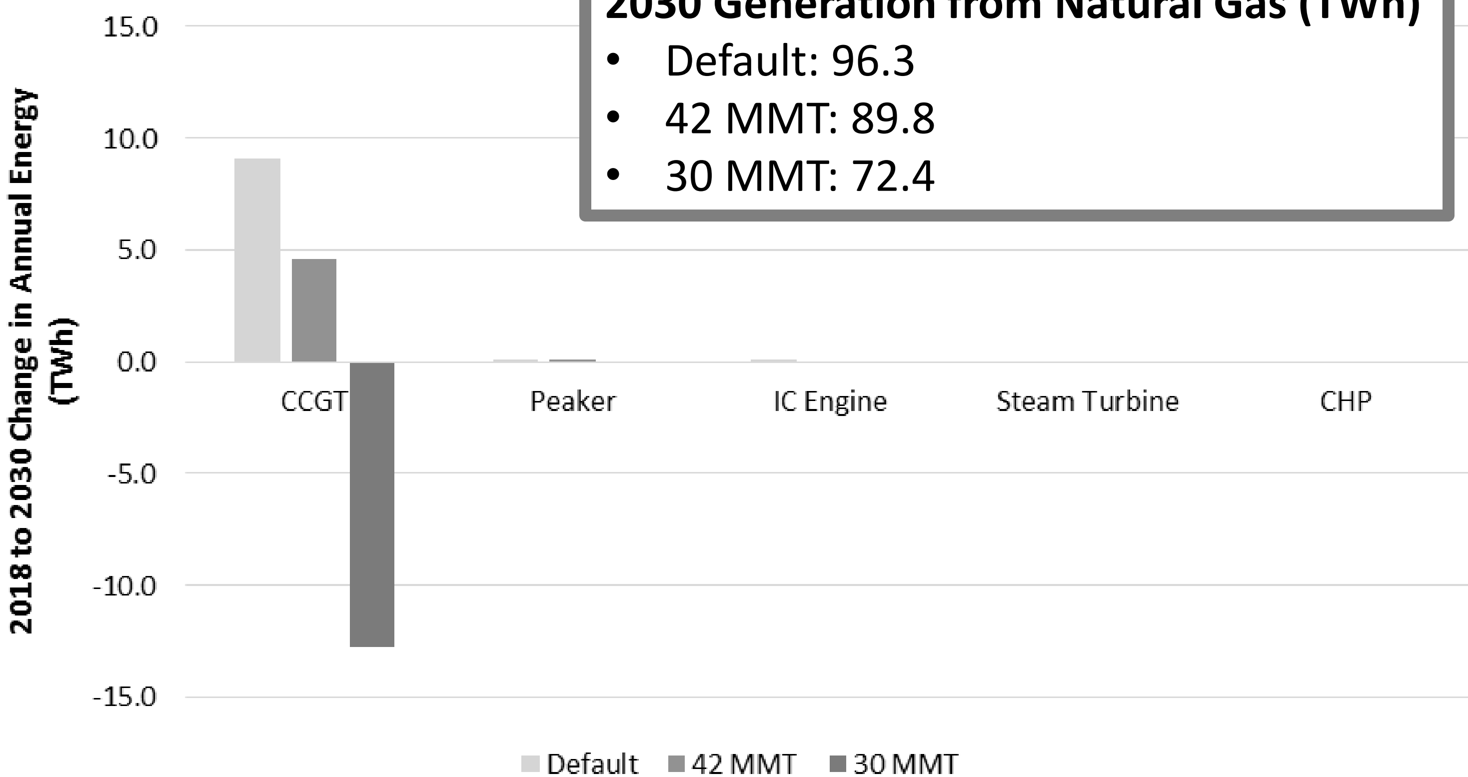
- There are disproportionately more MW of Peakers in DACs
- In theory, for every unit reduction of emissions from Peakers, DACs would benefit disproportionately relative to non-DACs (though difference is small)



Anticipated Change in Electricity Generation from Natural Gas Plants in California From 2018 to 2030

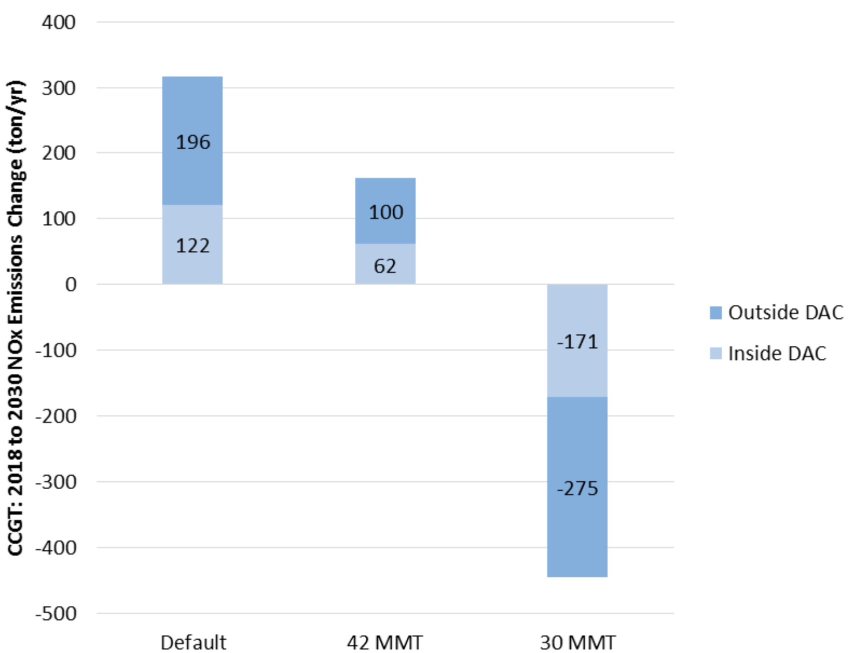
- Production changes most at CCGT plants
- The deemed GHG emissions factor that CARB assigns for imported electricity is larger than California CCGT emission factors , which can lead to more utilization of in-state generation and declining imports

2030 Generation from Natural Gas (TWh)
- Default: 96.3
- 42 MMT: 89.8
- 30 MMT: 72.4



Change in CCGT Air Pollutants
Statewide between 2018 and 2030

- Cycling CCGTs will increase NOx during unit-startups (not included)
- PM2.5 is not notably influenced by numbers of startups
- Changes in emissions at CCGTs do not disproportionately affect DACs on average



NOx

PM2.5

Change in Peaker Air Pollutants

Statewide between 2018 and 2030

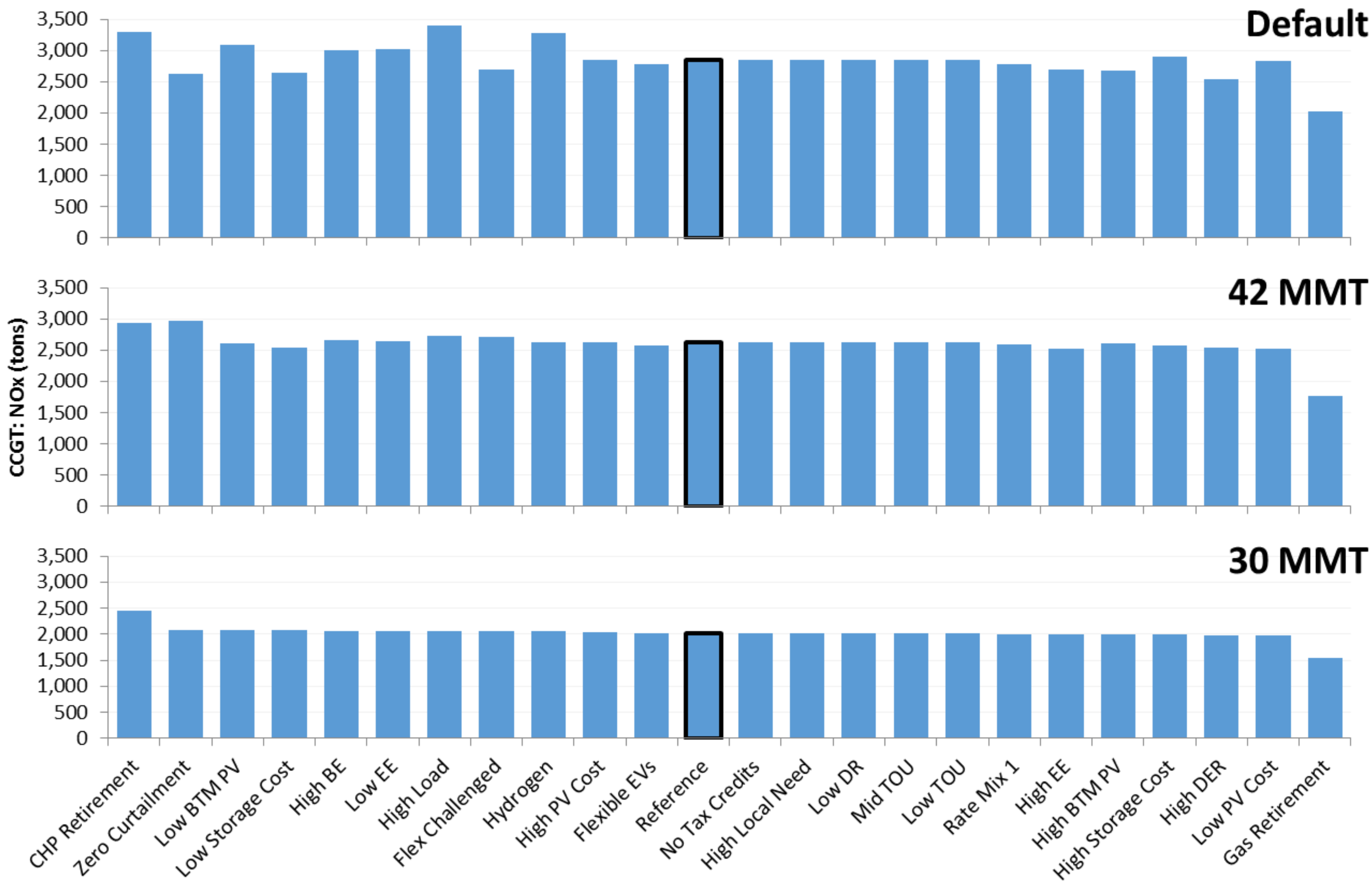
- Potential emissions changes within the Peaker class of power plants are much smaller than those for CCGT class
- Changes in emissions at Peakers may disproportionately affect DACs on average (actual impacts depend on how much individual plants are dispatched)

Note change in y-axis scale

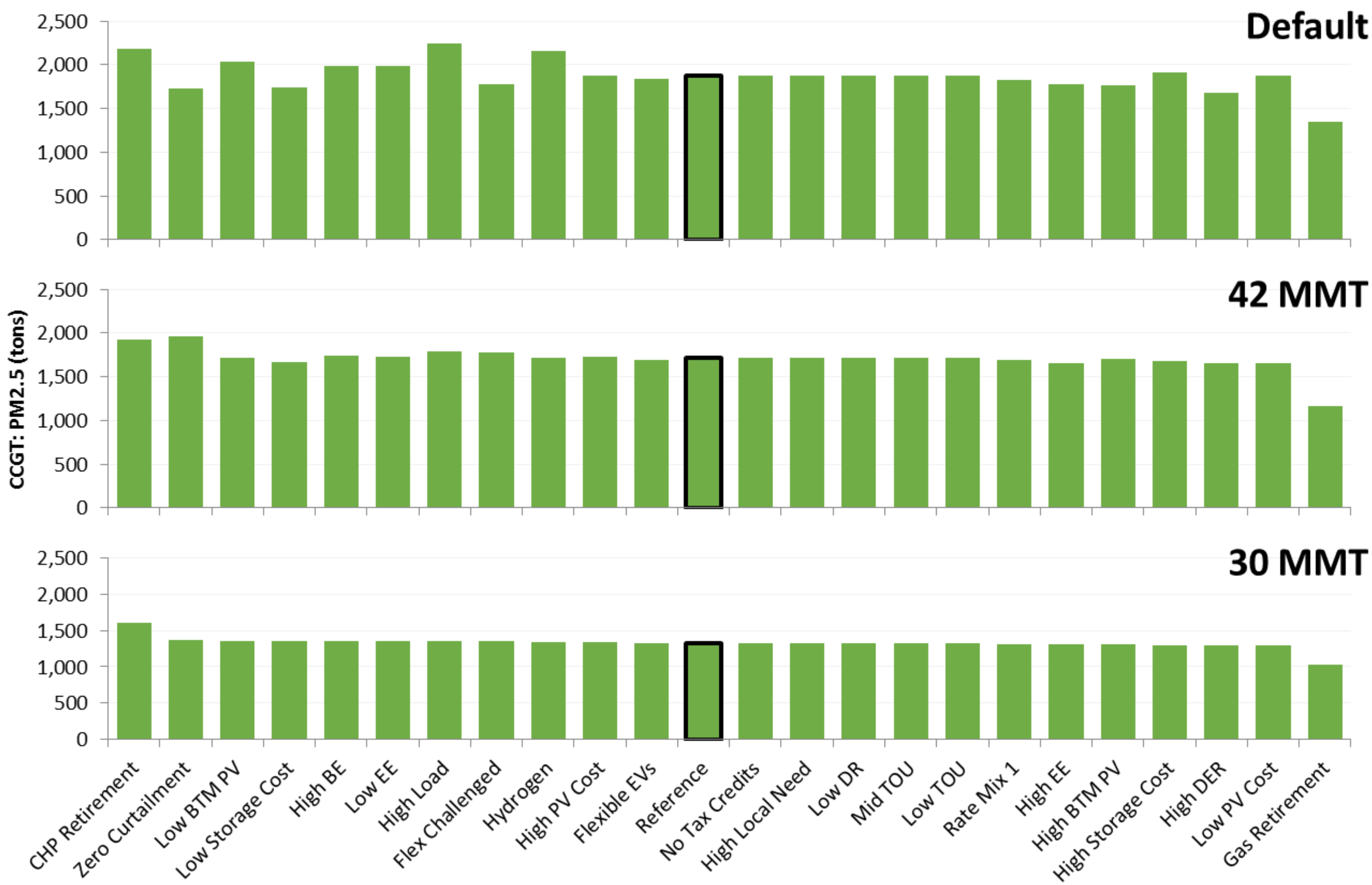
NOx

PM2.5

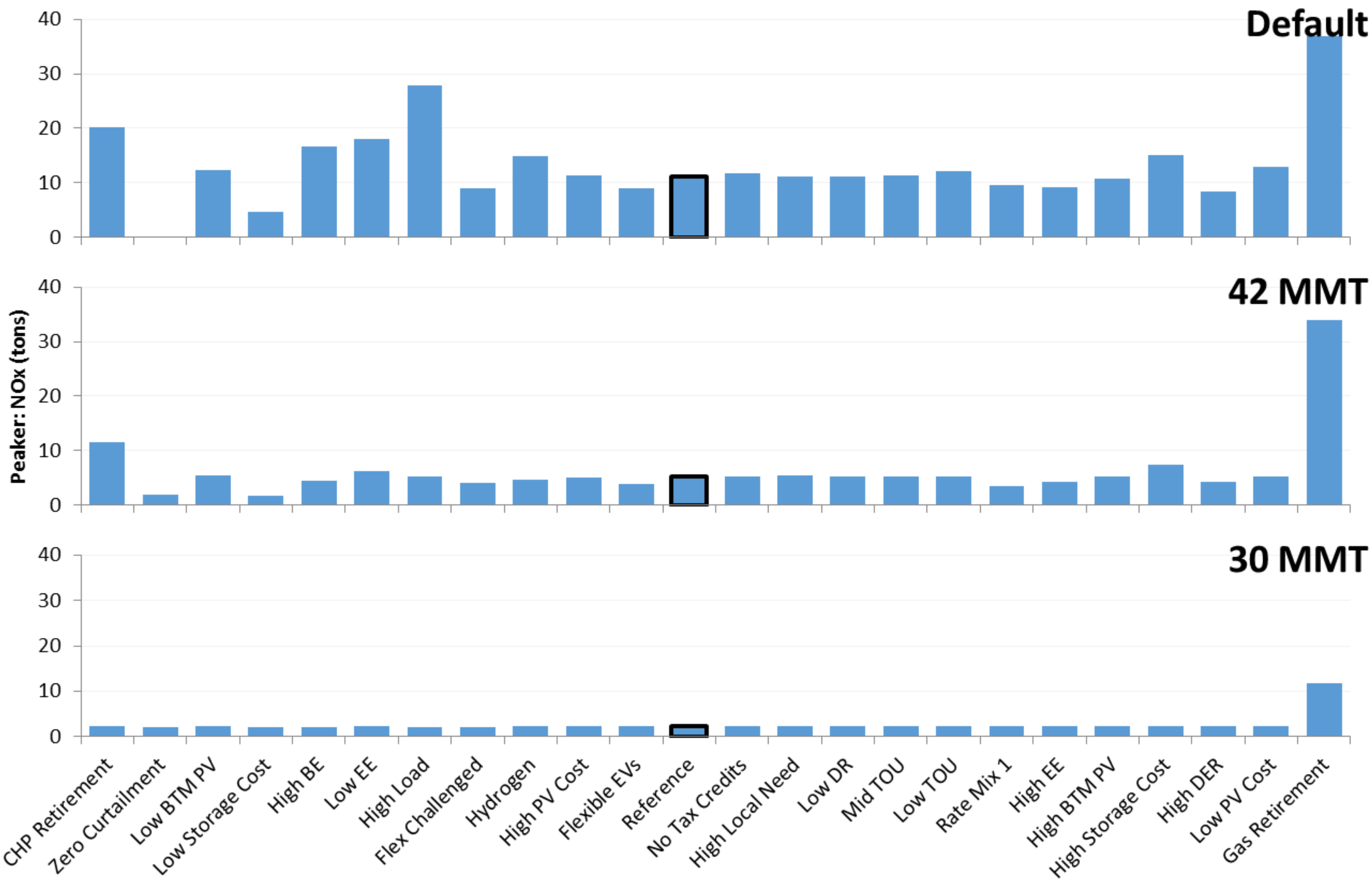
Statewide NOx from CCGTs Under Different GHG Targets in Optimal 2030 Portfolios (tons)



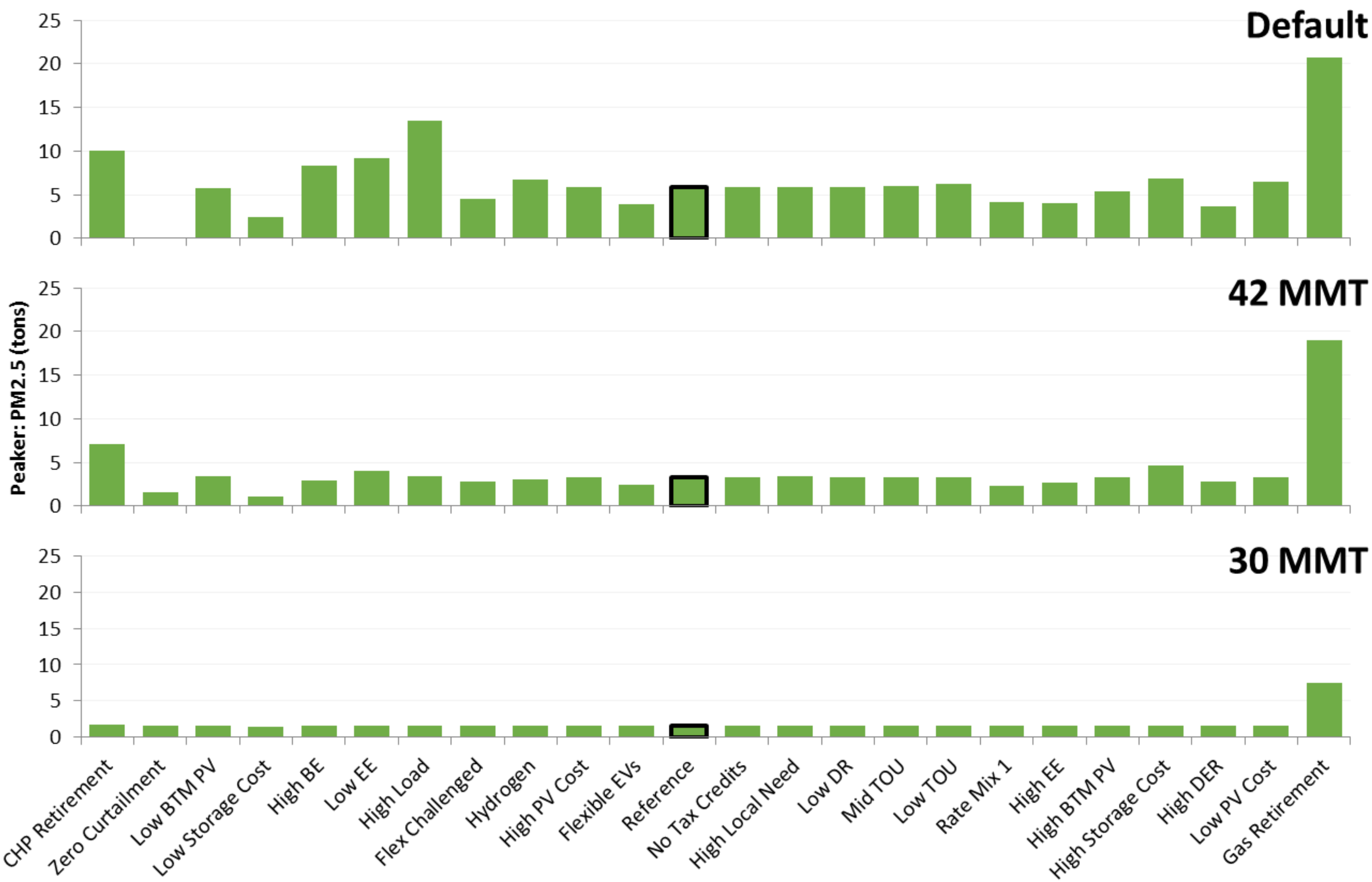
Statewide PM2.5 from CCGTs Under Different GHG Targets in Optimal 2030 Portfolios (tons)



Statewide NOx from Peakers Under Different GHG Targets in Optimal 2030 Portfolios (tons)

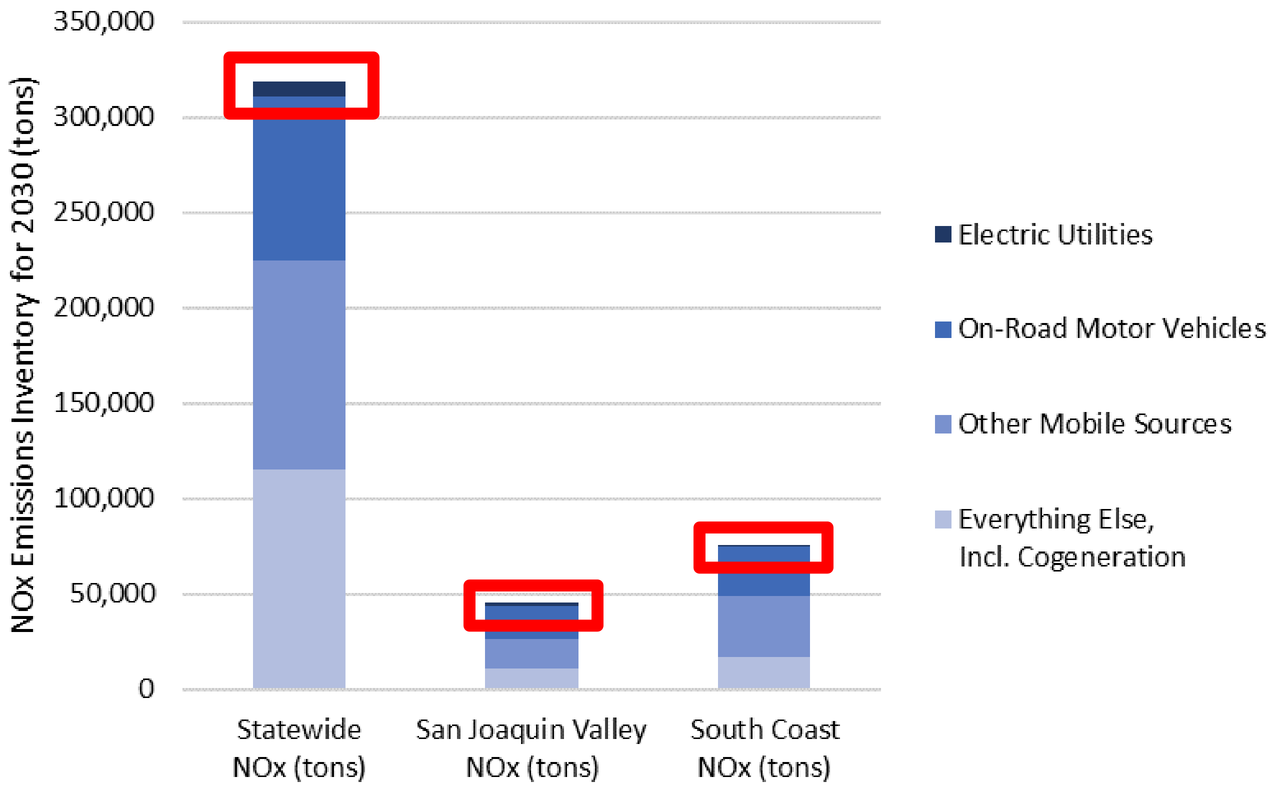


Statewide PM2.5 from Peakers Under Different GHG Targets in Optimal 2030 Portfolios (tons)



Contribution of NOx from Electricity Generation Compared with Mobile Sources

- Motor vehicles and other mobile sources create between 60-75% of overall NOx emissions, depending on location
- Electric utilities represent 2-4% of 2030 NOx emissions



"California Emissions Projection Analysis Model" which is an online tool at: https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php

Contribution of PM2.5 from Electricity Generation Compared with Mobile Sources

- Motor vehicles and other mobile sources create between 12-22% of overall PM2.5 emissions, depending on location
- Electric utilities represent 1-2% of 2030 PM2.5 emissions

"California Emissions Projection Analysis Model" which is an online tool at: https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php

Observations Regarding Air Pollutant Impacts

- The vast majority of electric sector emissions result from CCGTs, because they run more hours of the year.
- New renewables selected by RESOLVE primarily displace CCGT use during daytime hours.
- As the electric sector GHG Planning Target becomes more stringent, new renewables and storage displace more CCGT use outside of daytime hours.
- The largest opportunity to reduce air pollutants from the electric sector is by reducing the use of CCGTs.

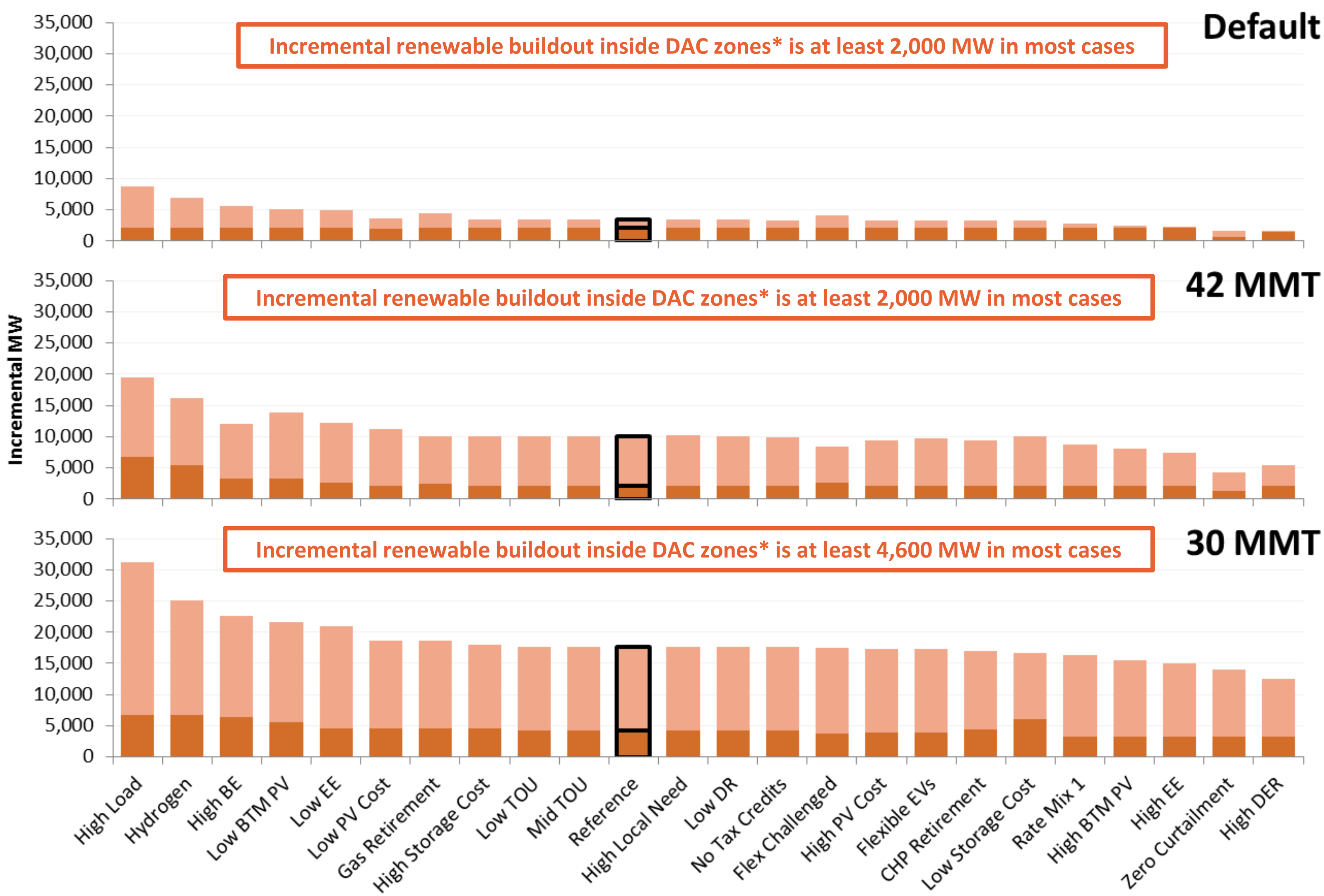
3.5. SELECTED RESOURCES IN DACS

Guide to DAC Resource Charts

- This subsection features a slide with bar charts that depict the total quantity of incremental resources (such as solar PV, wind, geothermal energy, and pumped storage) selected across a range of sensitivities that reflect different possible future conditions (see Appendix B for more detail on how each sensitivity is defined).
- Each bar depicts two pieces of information:
  - The total height of each bar represents the total quantity of resources selected in that sensitivity.
  - The smaller, darker color shows the quantity if resources in any of the four zones with 25% or more of their population in disadvantaged communities.
- The bar representing the reference case (default assumptions) for each Core Policy Case is outlined.

RESOLVE Output: Selected Resources

in Four Resource Zones Characterized by Disadvantaged Communities



*Dark orange section of bar

Observations Regarding Resource Selection in Disadvantaged Communities

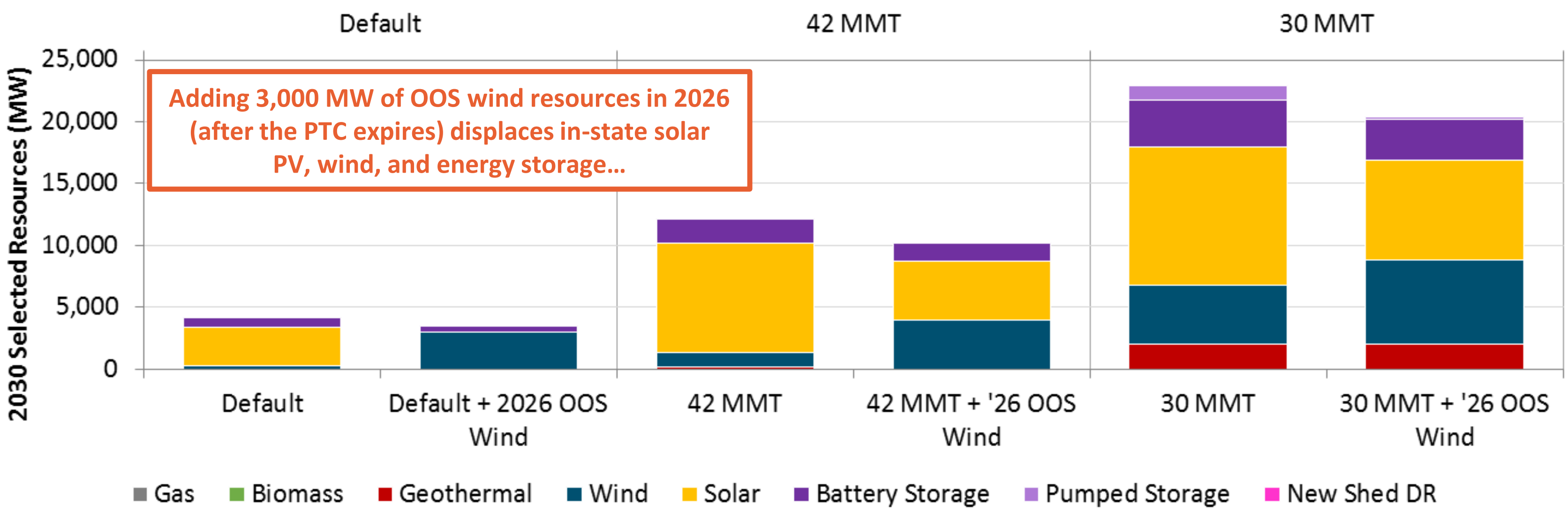
- The overall GHG target generally has a larger impact than other individual assumptions on the quantity of resources selected, including resources in disadvantaged communities
- Factors that increase load tend to increase resource selection, including resources in disadvantaged communities

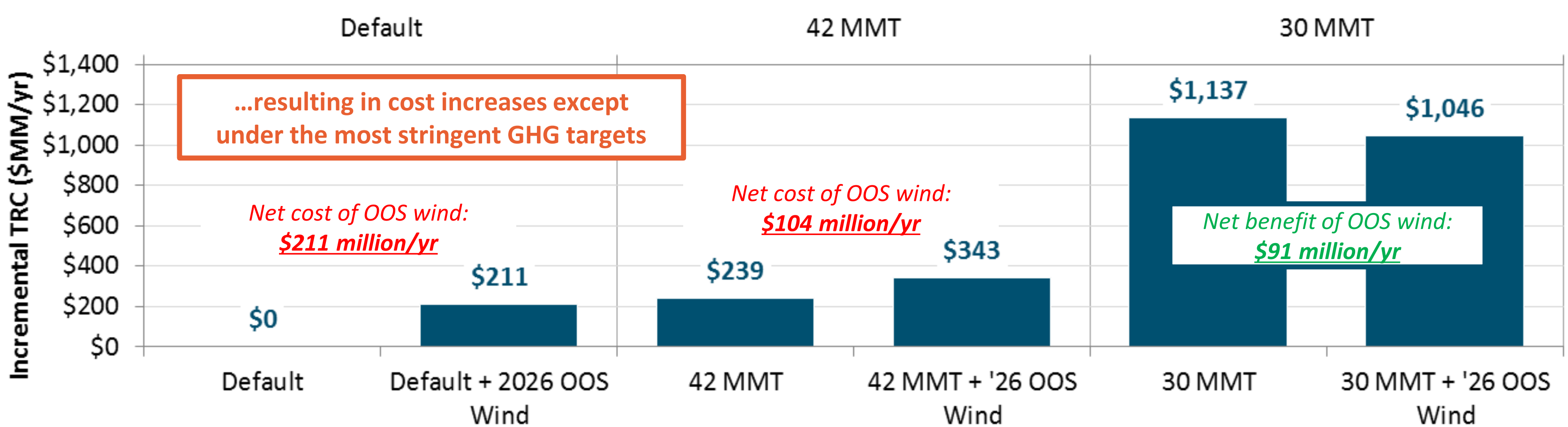
3.6. SELECTED RESOURCES AND COSTS IN RESOURCE STUDIES

Guide to Organization of Resource Studies Results

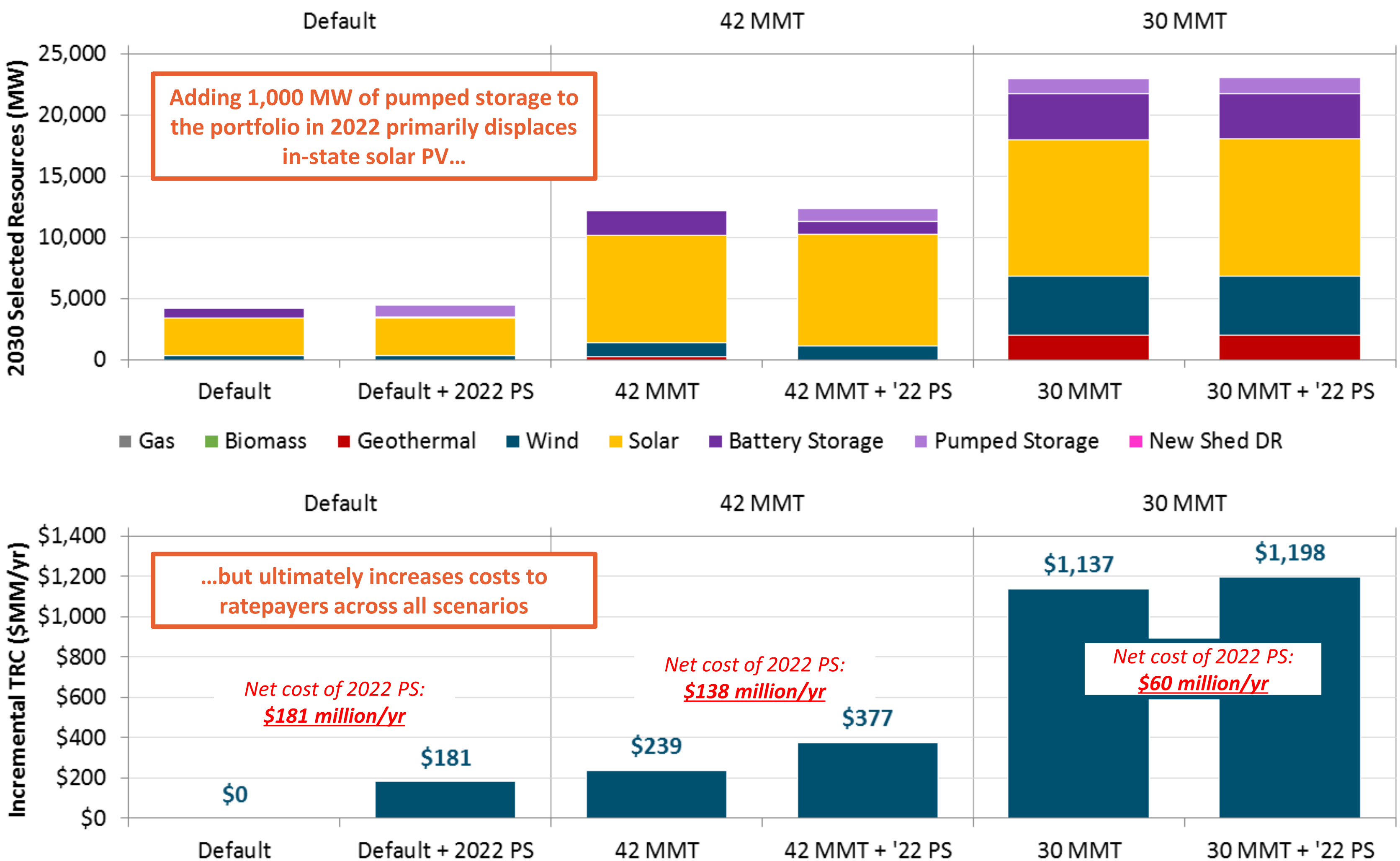
- For each of the three long lead-time resources studied, the slides in this subsection present information on:
  - how the composition of the optimal portfolio of additional resources changes when the resource of interest is manually added relatively early in the planning horizon
  - the impacts of those changes on incremental total resource cost
  - the effect of different assumptions about future conditions on the cost on impact of early procurement (see Appendix B for more detail on how each sensitivity is defined)
- Changes to the composition of the optimal portfolio and corresponding cost impacts are shown in the first set of slides as bar charts
- The effect of different future conditions on costs are shown as tables at the end of the subsection
- See also Section 2 and Appendix C for additional detail on how the Resource Studies were conducted

RESOLVE Output: Effect of Building OOS Wind in 2026 on Portfolio and Incremental TRC

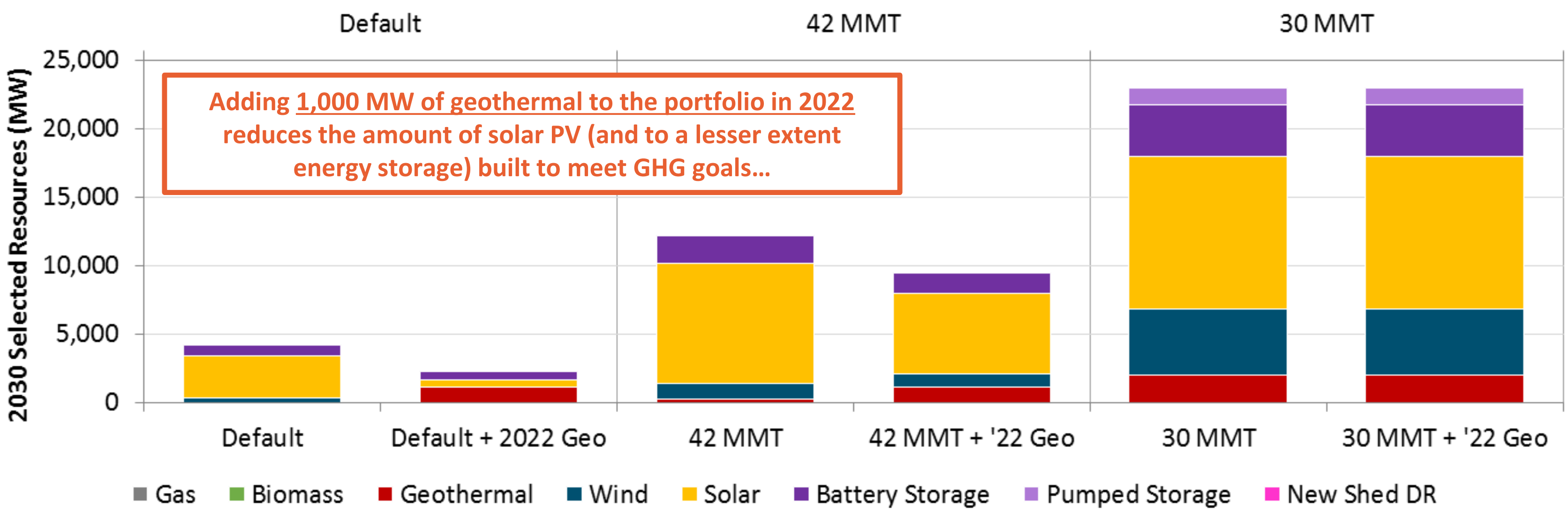


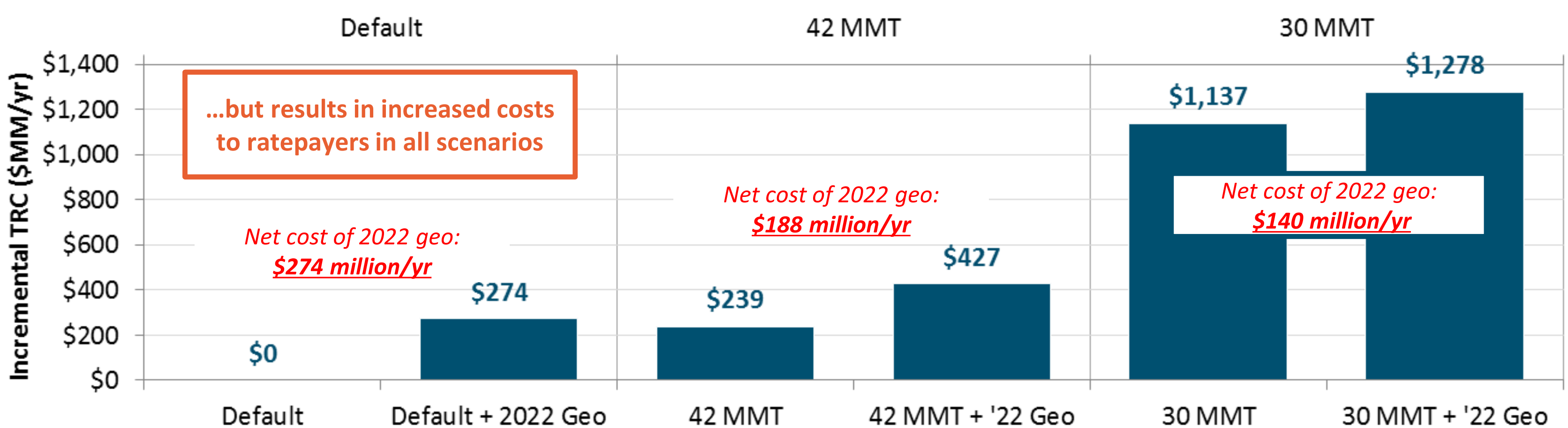


RESOLVE Output: Effect of Building Pumped Storage in 2022 on Portfolio and Incremental TRC



RESOLVE Output: Effect of Building Geothermal in 2022 on Portfolio and Incremental TRC





OOS Wind Built in 2026:
Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ 2026 OOS Wind	Change	Base Case	+ 2026 OOS Wind	Change	Base Case	+ 2026 OOS Wind	Change
Reference	**$0**	**$211**	**+$211**	**$239**	**$343**	**+$104**	**$1,137**	**$1,046**	**-$91**
High EE	$120	$341	**+$220**	$271	$410	**+$139**	$1,048	$994	**-$54**
Low EE	-$87	$107	**+$194**	$282	$334	**+$52**	$1,331	$1,211	**-$120**
High BTM PV	$471	$687	**+$217**	$677	$786	**+$109**	$1,577	$1,497	**-$80**
Low BTM PV	-$734	-$522	**+$212**	-$444	-$356	**+$88**	$480	$380	**-$100**
Flexible EVs	-$66	$155	**+$221**	$132	$262	**+$130**	$935	$863	**-$72**
High PV Cost	$240	$437	**+$198**	$510	$593	**+$84**	$1,419	$1,314	**-$105**
Low PV Cost	-$280	-$42	**+$239**	-$137	$20	**+$157**	$730	$687	**-$43**
High Battery Cost	$264	$473	**+$209**	$532	$619	**+$87**	$1,470	$1,373	**-$98**
Low Battery Cost	-$218	$3	**+$221**	-$9	$116	**+$125**	$617	$659	**+$42**
No Tax Credits	$69	$211	**+$142**	$382	$415	**+$34**	$1,391	$1,226	**-$165**
Gas Retirements	$351	$481	**+$130**	$480	$530	**+$50**	$1,233	$1,121	**-$112**

Pumped Storage Built in 2022: Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($B)		
	Base Case	+ 2022 PS	Change	Base Case	+ 2022 PS	Change	Base Case	+ 2022 PS	Change
Reference	$0	$181	**+$181**	$239	$377	**+$138**	$1,137	$1,198	**+$60**
High EE	$120	$303	**+$183**	$271	$432	**+$161**	$1,048	$1,115	**+$67**
Low EE	-$87	$91	**+$179**	$282	$407	**+$125**	$1,331	$1,391	**+$60**
High BTM PV	$471	$648	**+$177**	$677	$816	**+$140**	$1,577	$1,641	**+$64**
Low BTM PV	-$734	-$547	**+$187**	-$444	-$307	**+$137**	$480	$541	**+$61**
Flexible EVs	-$66	$119	**+$185**	$132	$286	**+$155**	$935	$997	**+$62**
High PV Cost	$240	$422	**+$182**	$510	$649	**+$140**	$1,419	$1,481	**+$62**
Low PV Cost	-$280	-$100	**+$180**	-$137	$4	**+$141**	$730	$791	**+$61**
High Battery Cost	$264	$441	**+$177**	$532	$647	**+$115**	$1,470	$1,529	**+$59**
Low Battery Cost	-$218	-$22	**+$195**	-$9	$155	**+$164**	$617	$754	**+$137**
No Tax Credits	$69	$254	**+$185**	$382	$536	**+$154**	$1,391	$1,467	**+$76**
Gas Retirements	$351	$472	**+$122**	$480	$585	**+$105**	$1,233	$1,294	**+$60**

Geothermal Built in 2022:
Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ 2022 Geo	Change	Base Case	+ 2022 Geo	Change	Base Case	+ 2022 Geo	Change
Reference	$0	$274	**+$274**	$239	$427	**+$188**	$1,137	$1,278	**+$140**
High EE	$120	$403	**+$283**	$271	$495	**+$224**	$1,048	$1,194	**+$146**
Low EE	-$87	$177	**+$264**	$282	$434	**+$152**	$1,331	$1,462	**+$131**
High BTM PV	$471	$748	**+$278**	$677	$870	**+$194**	$1,577	$1,718	**+$140**
Low BTM PV	-$734	-$457	**+$277**	-$444	-$261	**+$183**	$480	$614	**+$134**
Flexible EVs	-$66	$219	**+$285**	$132	$346	**+$214**	$935	$1,076	**+$141**
High PV Cost	$240	$502	**+$263**	$510	$684	**+$174**	$1,419	$1,562	**+$142**
Low PV Cost	-$280	$23	**+$303**	-$137	$94	**+$232**	$730	$871	**+$141**
High Battery Cost	$264	$537	**+$273**	$532	$706	**+$174**	$1,470	$1,609	**+$139**
Low Battery Cost	-$218	$66	**+$284**	-$9	$202	**+$211**	$617	$759	**+$143**
No Tax Credits	$69	$278	**+$210**	$382	$510	**+$128**	$1,391	$1,469	**+$78**
Gas Retirements	$351	$562	**+$211**	$480	$634	**+$155**	$1,233	$1,373	**+$140**

Observations Regarding Early Procurement of Long Lead-Time, Capital-Intensive Resources

- OOS wind is a resource that may represent a low-cost insurance policy against various risks of a high-PV portfolio
  - More detailed information is needed on different opportunities to access OOS wind to serve California load
- Other capital-intensive resources, including geothermal and pumped storage, increase costs if procured in the near term, but may reduce costs in 2030 if procured later

4. RECOMMENDATIONS

4.1. RECOMMENDED GHG PLANNING TARGET

42 MMT GHG Planning Target Mitigates Risks of Under- and Over-Procurement in Near Term

- The CPUC's current suite of policies may not be aggressive enough to meet future GHG reduction goals and are not optimized to reduce system costs
  - Cost-effective GHG reduction opportunities may not be available in other sectors, which could put overall state GHG reduction goal at risk
  - Failure to stimulate certain market segments may limit their ability to respond, or to continue to reduce costs, if needed later on (e.g., EE, storage)
- A 30 MMT statewide target by 2030 may be too aggressive in the near term
  - More cost-effective GHG reduction opportunities may be available in other sectors
  - Electrification of other sectors may increase electric sector loads
  - An aggressive GHG target, together with load departure and CCA renewable goals, could over-stimulate the market in short term
  - It exposes ratepayers to unnecessarily high costs
- Near-term procurement designed to achieve a 42 MMT GHG emissions level in 2030 balances the risk of doing too much too soon against the risk of doing too little, too late
- In future IRP cycles it may be useful to study more stringent GHG targets to help the electric sector prepare for greater reductions that will likely be needed after 2030 to achieve 2050 goals.

4.2. RECOMMENDED REFERENCE SYSTEM PORTFOLIO

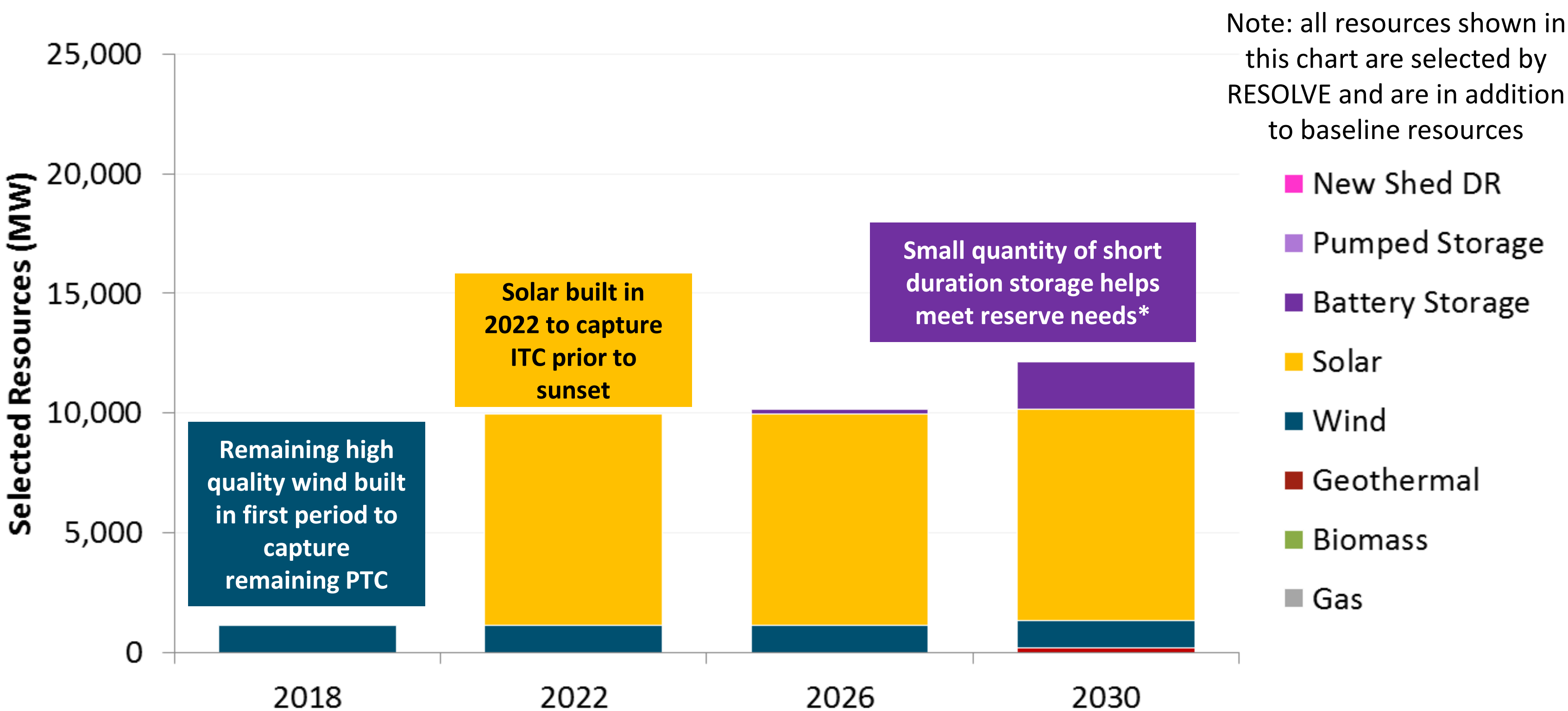
IRP-Related Statutory Requirements

(All references are to the Public Utilities Code)

- Identify a diverse and balanced portfolio (454.51)
- Meet state GHG targets (454.52(a)(1)(A))
- Comply with state RPS (454.52(a)(1)(B))
- Ensure just and reasonable rates for customers of electrical corporations (454.52(a)(1)(C))
- Minimize impacts on ratepayer bills (454.52(a)(1)(D))
- Ensure system and local reliability (454.52(a)(1)(E))
- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities (454.52(a)(1)(F))
- Enhance distribution system and demand-side energy management (454.52(a)(1)(G))
- Minimize air pollutants with early priority on disadvantaged communities (454.52(a)(1)(H))

Recommended Reference System Portfolio: 42 MMT Case

- Portfolio reflects ~9 GW of new utility-scale solar; 1,100 MW in-state wind; and 2,000 MW battery storage in addition to baseline that reflects existing policies
- Total incremental cost is $239 million/year, equivalent to approximately a 1% increase in system average rates by 2030



* Short-duration services could be provided by "Shimmy DR" resources, which were not modeled explicitly but may have resource potential up to 300 MW. The timing of the need for short duration services is based on a calculation of load-following reserve requirements outside of RESOLVE. There may be benefits to earlier procurement than shown here.

Deliverability Status of New Resources Selected by RESOLVE

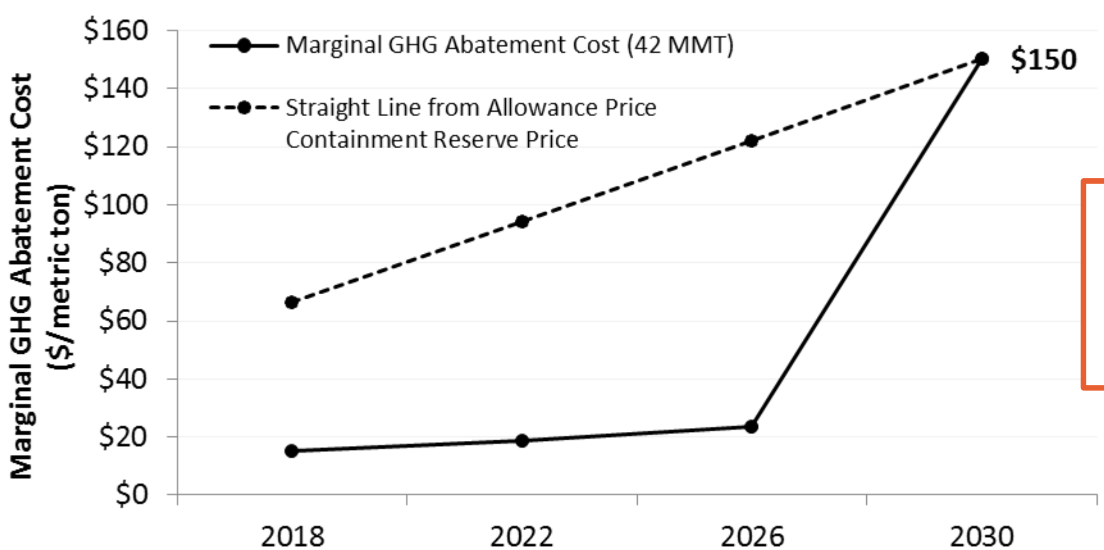
- 25% of new in-state resources selected as “Energy Only” resources, meaning:
  - Delivery Network Upgrades not required for interconnection
  - Resources may not be used for Resource Adequacy under current rules
- All Fully Deliverable resources are selected in areas of the state generally not expected to require major Delivery Network Upgrades based on CAISO staff estimates of transmission capability
- By procuring Energy Only resources consistent with the Reference System Portfolio, LSEs may reduce ratepayer costs by avoiding unnecessary transmission development

	Energy Only	Fully Deliverable
In-State Resources (MW, mostly PV)	**1,843**	**5,326**
Total (%)	**25%**	**75%**

4.3. RECOMMENDED GHG PLANNING PRICE

Recommended GHG Planning Price

- Staff recommends the GHG Planning Price corresponding to the Reference System Portfolio: $150/metric ton in 2030.
- For years before 2030, and to transition from the current GHG adder used in the IDER Proceeding, a straight line from the current GHG Allowance Price Containment Reserve price to the 2030 GHG Planning Price value would be reasonable



Staff proposes using a straight line from the current GHG allowance price containment reserve price (~$66/metric ton) to the 2030 GHG Planning Price value

Using the GHG Planning Price

- At a minimum, LSEs should use the GHG Planning Price to determine when and whether investments in GHG-free resources would reduce costs
  - Add the GHG planning price to the marginal cost of GHG-emitting resources
  - If the LSE adds a resource and it lowers total cost (including capital, fuel, variable, GHG allowance, etc.), then the resource would be justified
- LSEs may choose to make investments for reasons other than cost reduction (e.g., environmental goals, risk avoidance, etc.)

4.4. RECOMMENDED LSE-SPECIFIC GHG BENCHMARKS

Determining LSE-Specific GHG Emissions Benchmarks (1 of 2)

- Staff proposes that the Commission assign a "GHG Emissions Benchmark" to each LSE required to file a Plan
  - The GHG Emissions Benchmark will serve as a reference point for cross-checking the LSE's use of the GHG Planning Price
  - The GHG Emissions Benchmark is <u>not</u> intended to be enforceable or serve as a compliance mechanism
- The GHG Benchmark is calculated in two steps:
  - Divide the 2030 GHG Planning Target for the electric sector among CPUC-jurisdictional electric distribution utilities (EDUs) based on CARB's draft methodology for the 2021-2030 allowance allocation under the Cap-and-Trade program
  - Further divide that value proportionally among the host EDU and non-EDUs (CCAs and ESPs) within the host EDU's territory based on their projected 2030 load share.

Determining LSE-Specific GHG Emissions Benchmarks (2 of 2)

- The hypothetical example below reflects the recommended 42 MMT GHG Planning Target for 2030

LSE	Proportion of 2030 Allowance Allocation Under CARB's Cap-and-Trade Program	Proportion of 2030 Load Share Within the EDU Service Territory	2030 GHG Emissions Benchmark
EDU	30%	60%	7.56 MMT
CCA within EDU	N/A	35%	4.41 MMT
ESP within EDU	N/A	5%	0.63 MMT

4.5. SUMMARY OF RECOMMENDED GUIDANCE FOR LSE IRPS

Summary of Recommended Guidance for LSEs

- LSE Plans should include at least one portfolio that reflects the 42 MMT GHG Planning Target
  - LSEs should demonstrate consistency with the 42 MMT GHG Planning Target by using the associated GHG Planning Price ($150/metric ton)
- LSEs may submit multiple portfolios, subject to the following general considerations:
  - CPUC expects that the portfolios will reflect the use of the GHG Planning Price associated with the 42 MMT GHG Planning target ($150/metric ton)
  - CPUC expects any new resources to be consistent with the resources and timing reflected in the Reference System Portfolio
  - CPUC will gauge each LSE's use of the GHG Planning Price in part by comparing the LSE's forecasted load-based emissions to the LSE's specific GHG Emissions Benchmark
- Deviations from the above considerations are allowed, but LSEs must explain and justify any deviations
- CPUC will approve and certify IRPs and may authorize procurement by IOUs in 2018 or 2019

4.6. RECOMMENDED COMMISSION POLICY ACTIONS

Recommended Commission Policy Actions

- **Purpose of Recommended Policy Actions**
  - Ensure that LSEs develop or procure the incremental resources that may be needed as part of the 2017-2018 IRP Reference System Portfolio
- **Basis for Recommendations**
  - Staff have identified five conclusions based on IRP modeling that may require discrete policy actions by CPUC
  - Actions are intended to be undertaken by the CPUC, in tandem with other stakeholders where indicated
  - Actions correspond to conclusions, implications, and action items contained in the following section, “Path to Future All-Resource Planning”
  - Slides that follow summarize the conclusions and proposed policy actions

Review Renewable Energy Targets and Address Barriers to OOS Wind

1. **Consider Stimulating Additional Renewable Energy Procurement**
   - Conclusion: 42 MMT case indicates that significant renewable procurement would be optimal, potentially in the short-term
   - Policy Action: CPUC should evaluate whether it is reasonable to revise renewable energy targets to achieve the portfolios indicated in the IRP Reference and Preferred System Plans
2. **Address barriers to out-of-state (OOS) wind resources**
   - Conclusion: Out-of-state wind resources might be part of the optimal portfolio, but existing transmission may be insufficient to deliver the optimal quantity of OOS wind into CA
   - Policy Action: CPUC to coordinate with CAISO to convene intensive, rapid study of out-of-state (OOS) wind generation and transmission costs and procurement options
     - Option 1: Transmit policy-preferred portfolio reflecting one or more approaches to serving CA load with OOS wind to CAISO's Transmission Planning Process
     - Option 2: Conduct study under the aegis of a broader regional western transmission planning process

Use Common Planning Assumptions Across Proceedings

3. **Use the GHG Planning Price in Integrated Distributed Energy Resource (IDER) proceeding**
   - Conclusion: IRP has the ability to produce marginal abatement prices that reflect the system-wide marginal resource abatement cost associated with achieving certain targets, such as GHG or RPS targets
   - Policy Action: IRP should adopt marginal abatement prices that can be used by other CPUC proceedings, including the IDER proceeding
4. **Develop a Common Resource Valuation Methodology (CRVM)**
   - Conclusion: Effective IRP planning requires a clear link to procurement activity, which can potentially be provided via a consistent valuation methodology applied in both planning and procurement processes and across multiple resource areas
   - Policy Action: CPUC and stakeholders will work to develop a CRVM to ensure that the costs and benefits used in IRP planning are reflected in bid evaluation and program funding authorizations across resource types

Recommended Commission Policy Actions

5. **Study natural gas fleet impacts**
   – Conclusion: A certain subset of existing gas plants may provide value to the system in 2030, though which plants or plant attributes provide value in 2030 is still unclear
   – Policy Action: CPUC should coordinate with CAISO to engage in a detailed study in order to:
     - Identify attributes of the existing generation fleet that will provide value in the future
     - Continue to explore multi-year RA planning horizons and their impacts

5. PATH TO FUTURE ALL-RESOURCE PLANNING

Path to Future All-Resource Planning: Components

Articulated for each resource area

- **Conclusions**: Derived from the preliminary RESOLVE modeling results
- **Implications**: Policy considerations for specific resource areas given the IRP modeling results
- **Action Items:** Next steps for resource areas to develop a further factual record given the new policy considerations

Path to Future All-Resource Planning: Expected Purpose, Use, and Outcome

- **Purpose**: The Commission aims to optimize more resources such as energy efficiency, demand response, and electric vehicles in future cycles.
  - To do so requires developing policy ideas and building a record in resource proceedings so that resource-specific assumptions and policies can be weighed by the appropriate assigned Commissioner, Administrative Law Judge, and parties.
- **Plan:** Staff will build on party comments on these Conclusions, Implications, and Action Items to develop next steps in coordination with resource proceedings.
- **Outcome:** Upcoming scoping memos in specific resource proceedings will set out actions, timelines, and deliverables to build the required record.

Path to Future All-Resource Planning: Expected Benefits

- IRP process optimizes more demand-side resources in the 2019-20 IRP cycle
- IRP process continues to comply with statutory mandate to identify a diverse and balanced portfolio of resources needed to meet California's electricity needs
- IRP process continues to place downward pressure on costs to ratepayers by using assumptions and policies that draw on prior IRP results
- Ensure that planning guidance developed in IRP flows into DAC-related proceedings and results in actions consistent with statutory guidelines

Energy Efficiency (1 of 2)

Conclusions:

- Future value of incremental energy efficiency depends on the magnitude of the GHG Planning Target
- Inputs used in current IRP analysis may understate EE costs, thus potentially resulting in overstated benefits
- Shape and magnitude of avoided costs change dramatically in a carbon-constrained world

Implications:

- Further effort necessary to examine feasibility of EE resource optimization in future IRP modeling
- Alignment of EE rolling portfolio cycle, IRP cycles, and other processes may be beneficial
- EE resources may require updated price signals to ensure future program development that benefits the grid

Energy Efficiency (2 of 2)

Action Items:

- Refine workplan for determining whether EE Potential & Goals process can be integrated with IRP Reference Plan development in 2019
  - July 2017: Scoping of consultant work
  - November 2017: Navigant completes post-processing of current EE P&G in order to study feasibility of EE optimization in the future
  - Early 2018: EE Staff whitepaper addressing feasibility and potential means of EE optimization, mailed for comment in EE proceeding
- Perform gap assessment on whether EE rolling portfolio cycle and IRP cycle can be aligned
- Examine opportunities for alignment with other connected processes such as IEPR forecast and SB 350 targets
- Assess potential impacts of new price signals that may originate from IRP and EE providers' ability to respond to those signals

Behind-the-Meter PV (1 of 2)

Conclusions:

- Increasing quantities of BTM PV increase total resource cost across all scenarios, with significant portion of costs being borne by customer generation owners
- While rooftop solar and utility-scale solar have a similar operational impact on GHG emissions, the total resource cost of rooftop solar is higher than utility-scale solar because of economies of scale and resource quality
- Location-specific distribution and certain transmission deferral benefits not considered in RESOLVE

Implications:

- CPUC NEM Successor Tariff proceeding should consider IRP modeling results when designing future NEM tariffs.
- CPUC should define a consistent means of valuing BTM PV resources across proceedings.
- NEM Successor Tariff proceeding would benefit from location-specific values generated by DRP

Behind-the-Meter PV (2 of 2)

Action Items:

- Improve valuation methodology for BTM PV resources in IRP:
  - Consider appropriateness of using the Total Resource Cost (TRC) test vs. other demand-side cost-effectiveness tests
    - TRC test currently used in 2017-18 IRP modeling
  - Consider the appropriate procedural venue (IRP or NEM) to determine which valuation methodology to use.
- Establish coordination workplan with CEC on rollout of ZNE Building standards, if adopted, and related implications for BTM PV
- Establish coordination workplan for alignment with DRP and NEM Successor Tariff Revisit

Demand Response (1 of 3)

Conclusions:

- "Shed" DR resources do demonstrate value at the local level and in a sensitivity that assumes high gas generation retirements
- Additional "shed" DR resources beyond those included in the baseline do not demonstrate value at system level
  - 2017 IRP is based on the assumption that the established PRM standard and the incremental local needs defined in CAISO's technical studies in 2016 will ensure sufficient resources are available to meet contingency planning requirements in local transmission constrained areas, as well as emergency needs. Should either the PRM or local needs change, the value of incremental "shed" DR could change.
- At higher levels of GHG constraints, advanced "shift" demand response offers a cost-effective option to increase flexibility of the electric system
- "Shimmy" DR resources could meet some portion (up to 300 MW) of the need for short-duration storage services provided by battery storage, at lower cost
- The IRP baseline case for DR does not reflect the rate designs currently contemplated for the planned 2019 default of residential customers onto TOU rates, or the later 4 p.m. – 9 p.m. peak window recommended by the CAISO and adopted for San Diego Gas & Electric and under consideration for Southern California Edison and Pacific Gas & Electric, or market transformation of automated controls that may enhance TOU uptake

Demand Response (2 of 3)

Implications:

- “Shed” DR not a cost effective incremental system resource but could be in local areas; requires further study
- At more stringent GHG constraints, “Shift” DR resources represent a cost-effective means of reaching GHG emissions targets, assuming those resources materialize in the time horizon studied and at the costs assumed in the LBNL DR Potential Study
- “Shimmy” DR resources require further development
- Potential uncertainty regarding the procurement trajectory over the IRP time horizon should be considered in planning and targets for different DR resource types

Demand Response (3 of 3)

Action Items:

- Develop a transition plan that can address gaps that RESOLVE does not model
- Maintain and/or build resources so they will be in place to meet long-term needs
- DR proceeding should evaluate how IRP results should affect DR targets and program budgets post-2022.
- Refine workplan for determining whether EE Potential & Goals and DR potential study processes can be integrated with IRP Reference Plan development in 2019
- Continue to pursue steps to make “shift” and “shimmy” DR resources a reality
- Determine how current DR cost-effectiveness regime can integrated with a common resource valuation methodology developed in IRP in close coordination with IDER proceeding

Electric Vehicles

Conclusions:

- In the 42 MMT and 30 MMT Cases, flexible EV charging reduces the amount of renewable generation and energy storage selected to meet GHG Planning Target
- Financial benefit of flexible charging grows with increasing penetrations of renewables (or increasingly stringent GHG targets)

Implications:

- The CPUC should prioritize investments in EV charging infrastructure that facilitates charging flexibility, as it contributes to renewables integration and reduces total system costs
- The CPUC should ensure that rates are designed to encourage EV charging behavior that is responsive to grid conditions and flexibility needs
- The CPUC should use IRP modeling results to inform EV program investment decisions during the next round of EV applications (and in the current round, to the extent possible)
- To determine how much CPUC should invest in EV programs and incentives, a better understanding is needed of:
  - The load impact of managed EV charging in comparison to unmanaged EV charging
  - The bill impacts of existing and future programs
  - Relationship between charges “at the pump” and electricity bill charges on total household bills
  - Willingness of customers to bear higher rates in short-term
  - The level of EV adoption at which rate decreases begin to occur

Action Items:

- Coordinate with CEC and CARB to further refine state forecasts for EVs
- Investigate opportunities to electrify the transportation sector to take advantage of the GHG and air emissions benefits associated with an increasingly clean electric grid and provide benefits to disadvantaged communities

Energy Storage

Conclusions:

- Optimal levels of battery and pumped storage depend on GHG target, and may vary from LSE to LSE
- Increased renewable penetration and need for short-duration balancing services in 42 and 30 MMT Cases results in significant need for additional storage in most sensitivities
  - Most storage added across sensitivities is short-duration (~1 hr)
- Addition of pumped storage could be beneficial in high-GHG constrained futures
  - Procurement in the near-term results in some cost increases across all scenarios

Implications:

- Additional battery storage goals should consider the ongoing GHG target-setting efforts in IRP
- No near-term action is necessary in setting targets for procurement of pumped storage
- Battery storage value stacks used in IRP modeling could benefit from further development

Action Items:

- Establish workplan to capture all distribution- and customer-level values of energy storage for future IRP cycles
  - Leverage current Multiple Use Applications (MUA) work
  - Coordinate with DRP proceeding for potential provision of these and other values for storage resources

Renewables (1 of 2)

Conclusions:

- Significant renewable energy resource procurement is required in the 42 MMT and 30 MMT cases
  - Utility-scale solar and wind resources are required in significant quantities
  - Geothermal is only required in high-GHG constrained futures
  - Biomass is likely not needed prior to 2030
- Expiry date of ITC/PTC may have effect on optimal timing for renewable energy resource procurement
- Curtailment is a cost-effective solution for grid integration

Implications:

- CPUC and stakeholders should evaluate the feasibility of large amounts of renewable energy procurement over a short timeline and whether RPS is an appropriate mechanism for that procurement
- ITC/PTC expiry dates may drive timing of decision-making and procurement
- RPS and IRP proceedings would benefit from a high degree of alignment

Renewables (2 of 2)

Action Items:

- Evaluate how the IRP Reference and Preferred System Plans should inform the RPS procurement targets in the RPS proceeding
- Reform the RPS Least Cost Best Fit (LCBF) methodology prior to a potential 2018 RPS RFO, as part of IRP's development of a Common Resource Valuation Methodology (CRVM)
- Assess the procurement, project permitting/construction, and interconnection issues associated with accelerating renewable energy procurement to capture expiring ITC and PTC tax credits
- Require IOUs to include analysis in their respective 2018 RPS Procurement Plans that examines the trade-off between ITC expiration and the potential decline in future resource costs

IDER

Conclusions:

- IRP has the ability to produce marginal abatement prices that reflect the system-wide marginal resource abatement cost associated with achieving certain targets, such as GHG or RPS targets

Implications:

- Other proceedings can use marginal abatement prices provided by IRP in their planning, valuation, and procurement processes

Action Items:

- IRP should determine how marginal abatement prices (i.e. the GHG Planning Price) should flow into IDER cost-effectiveness methodologies
- IRP should develop a Common Resource Valuation Methodology (CRVM) in close cooperation with IDER staff
- Staff should identify specific data needs and timing of information flows between IDER and IRP

DRP (1 of 2)

Conclusions

There are two major interaction areas between IRP and DRP:

- Grid integration costs and benefits of DERs at system level need to be calculated
  - RESOLVE does not currently account for grid integration costs and benefits of DERs
  - DRP future refinements to the locational net benefit analysis (LNBA) include calculation of net DER integration costs at the Distribution Planning Area level, but calculation of a system level costs/benefits is not currently in scope of LNBA working group
- Transparent and consistent DER growth forecasts are needed for both IRP and DRP
  - IRP needs a clear set of planning assumptions in order to run scenarios on the impact of policy levers on each DER
  - DRP staff is coordinating CEC on development of DER growth scenarios, and ensuring the process will meet IRP needs
  - Currently discussing what adjustments may be needed to the IEPR demand forecast process to meet IRP and DRP needs

DRP (2 of 2)

Implications:

- DRP and IRP comprise a feedback loop: DER growth depends on the cost-effectiveness of DER relative to other GHG free resources, which depends on costs of grid integration of DERs, which in turn depends on DER growth
- This feedback loop makes the assessment of DER growth and cost effectiveness complex, and by necessity an iterative process
  - DRP will not inform the 2017-2018 IRP planning cycle or vice versa, but results will be for the following cycle
  - IRP guidance from the optimized portfolio is expected to flow through to policy revisions in CPUC resource proceedings, and then the IEPR forecast, before becoming new DRP DER growth scenarios
- New analysis that pulls together results of LNBA in order to understand impacts at a system level may be needed

Action Items:

- DRP to develop a plan for determining system level grid integration costs/benefits
- DRP to work with CEC to define planning assumptions for DER growth
- DRP staff to determine how optimization of DERs in future IRP cycles will impact DER growth forecasts
- DRP to identify which DERs are driving specific grid needs, so that grid planning can adjust to changing market adoption rates

Disadvantaged Communities (1 of 2)

Conclusions:

- The overall GHG target generally has a larger impact than individual assumptions on the level of localized air pollutants
- Factors that increase load tend to increase localized air pollutant emissions from power plants and vice versa
- Fuel consumption and emissions changes within the CCGT class of power plants greatly outweigh those from other plant classes
  - Reducing CCGT use as part of a plan to achieve a GHG planning target (e.g., 42 MMT) achieves the greatest quantities of reductions in localized air pollutants, including in DACs

Disadvantaged Communities (2 of 2)

Implications:

- Individual plant operations would need to be examined in future planning processes to assess true impact on DACs
- IRP will benefit from a clear understanding of what gas plant attributes can provide the most value to the grid in 2030

Action Items:

- Common Resource Valuation Methodology (CRVM) development should attempt to capture benefits to disadvantaged communities
  - LSE valuation of individual resources and the specifics of proposed project could take into account the benefits or detriments to a disadvantaged community
    - Where project location falls relative to most recent DAC location
    - Whether the project ensures preferred resources in DACs are prioritized over other resource options

Common Resource Valuation Methodology (CRVM)

Conclusions:

- Effective IRP planning requires clear linkages to procurement activities
- A CRVM could provide a link between the values used in planning and procurement activities, both for supply and demand-side resources
- Large amounts of additional renewable resources may be needed in the short term to meet the State's GHG goals

Implications:

- A CRVM should be developed in time for use in the LSEs summer 2018 RPS Procurement Plan filings, which represent the first opportunity for IRP-informed procurement

Action Items:

- CPUC and stakeholders should work to develop a CRVM to ensure that the costs and benefits used in IRP planning are reflected in bid evaluation and program funding authorizations across resource types

APPENDIX A
IMPACTS ON DISADVANTAGED COMMUNITIES

Disadvantaged Communities Analysis

- This appendix provides additional detail on how the disadvantaged communities analysis reported in the Reference System Plan was conducted
- While some slides that appeared in the body of the Reference System Plan are repeated here, this appendix also provides additional information on the questions that framed the analysis and how it was structured.

A.1. LOCALIZED AIR POLLUTANTS IN DISADVANTAGED COMMUNITIES

Approach to Analyzing IRP Impact on Localized Air Pollutants in DACs

Statutory Goal for IRP

- "Minimize localized air pollution and other GHG emissions, with early priority on disadvantaged communities"

Analytical Approach

- **Step 1**: Characterize the distribution of power plant classes inside and outside DACs
- **Step 2**: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default, 42 MMT, and 30 MMT
- **Step 3:** Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

Characteristics of Power Plant Types in IRP Modeling

RESOLVE groups plants with similar operating characteristics into different classes:

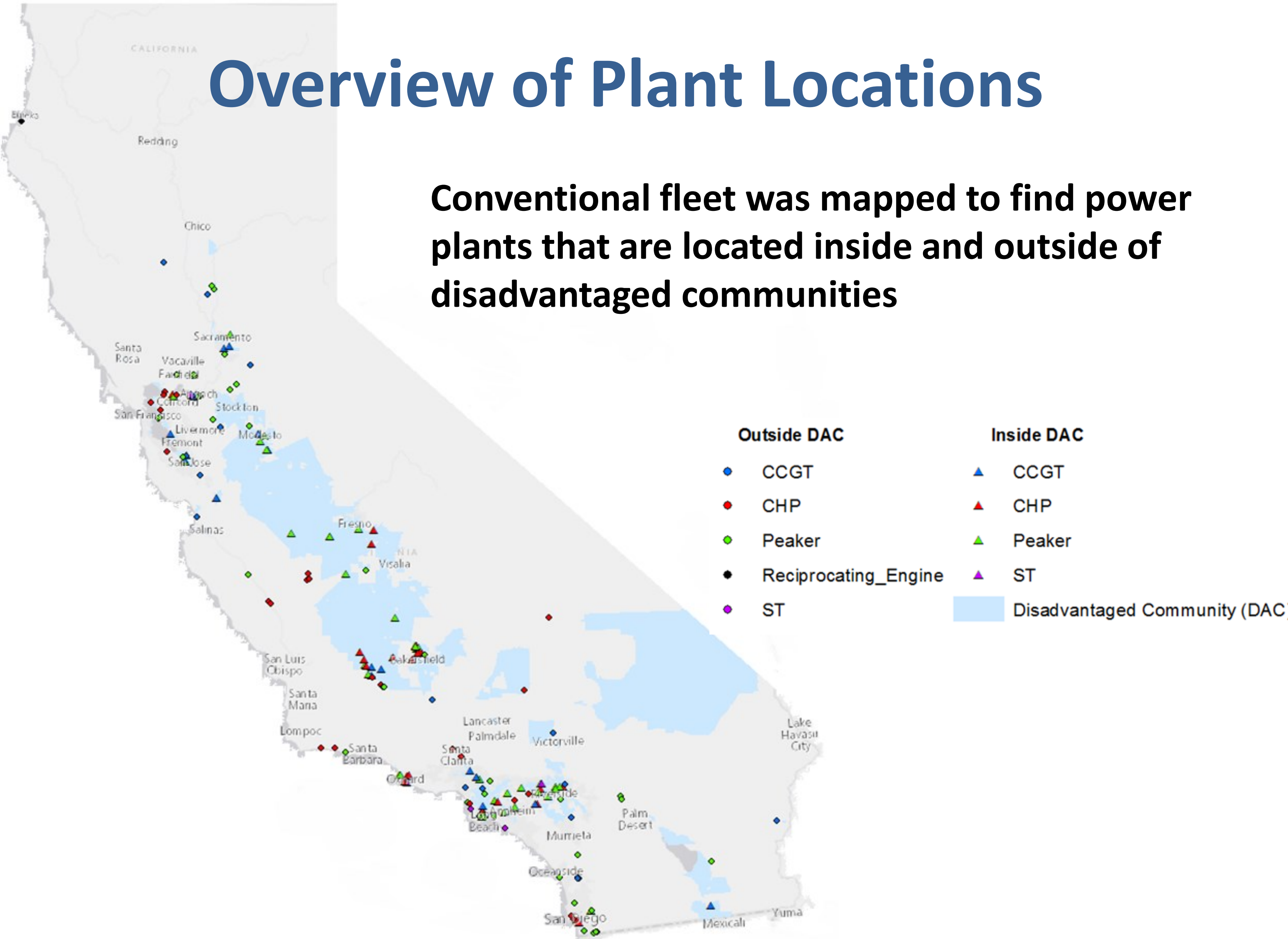
Plant Class	Description	Representative Heat Rate at Pmax (Btu/MWh)	Examples
CCGT	Combined Cycle Gas Turbine	7-8	Otay Mesa, Colusa, La Paloma
Peaker	Single Cycle Gas Turbine	9-12	Sentinel, Long Beach, Panoche Peaker
IC Engine	Internal Combustion Engine or Reciprocating Engine	9.1	Humboldt bay
ST	Steam Turbine	9.7	Etiwanda, Alamitos
CHP	Combined Heat and Power	7.6*	Crockett, Algonquin Sanger, Watson, Sycamore

*Based on assumptions in the Scoping Plan this value likely underestimate CHP heat rates

See the revised *RESOLVE Inputs and Assumptions* document for details, available at: www.cpuc.ca.gov/irp/prelimresults2017

Overview of Plant Locations

Conventional fleet was mapped to find power plants that are located inside and outside of disadvantaged communities



Power Plant Capacity in Current Physical California Fleet Is Disproportionately Located in Disadvantaged Communities

- DACs defined in IRP as CalEnviroScreen 3.0 results for top 25% scoring areas by census tract
- If capacity from natural gas power plants was distributed throughout the CA population randomly, one would expect to find about 25% of it in DACs
- In fact, 39% is in DACs, a disproportionate share

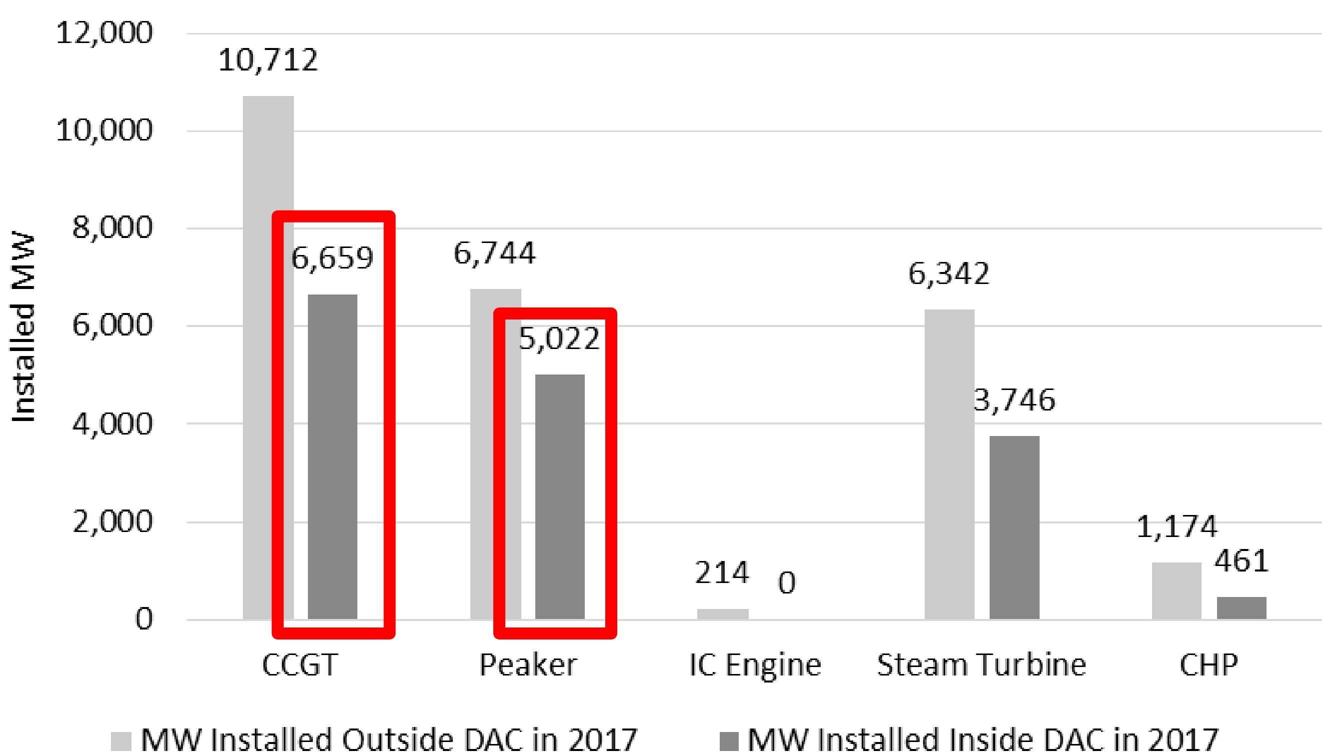
Statewide, from CalEnviroScreen 3.0	Statewide Total	Outside DAC	Inside DAC	Outside DAC (%)	Inside DAC (%)
Population	37,253,956	27,916,231	9,337,725	75%	25%
Number of Census Tracts	8,035	6,052	1,983	75%	25%
Conventional Power Plants (Installed MW)	41,200	25,121	16,079	61%	39%

Two Ways to Prioritize Plants Affecting DACs

- **Absolute**: the plant types with the highest absolute amount of capacity in DACs
  - Reducing emissions from these plants might have the greatest absolute benefits for DACs, but would benefit non-DACs even more
- **Relative**: the plants that occur disproportionately in DACs relative to non-DACs
  - Reducing in emissions from these plants would have the greatest relative impact on DACs compared to non-DACs

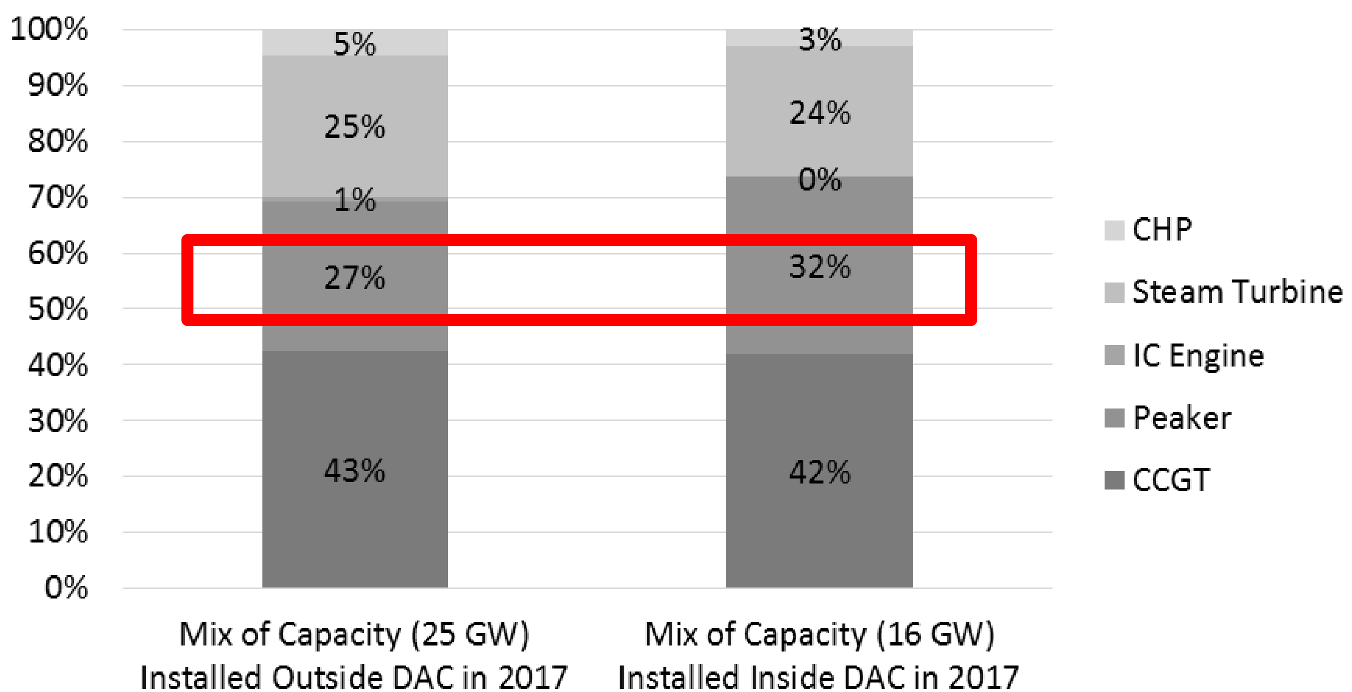
Absolute Frequency Distribution of 2017 Fossil Capacity in California By Power Plant Type

- The most common plants in DACs by capacity are CCGTs and Peakers
- Reductions from these plants may have the greatest absolute impacts on localized air pollutants from the electric sector



Relative Frequency Distribution of 2017 Fossil Capacity in California by Power Plant Type

- There are disproportionately more MW of Peakers in DACs
- In theory, for every unit reduction of emissions from Peakers, DACs would benefit disproportionately relative to non-DACs (though difference is small)



Step 1 Conclusions

Step 1: Characterize the distribution of power plant classes inside and outside DACs

- The largest amount of capacity in DACs comes from CCGTs and Peakers
- The most disproportionate amount of capacity in DACs comes from Peakers

Approach

Step 1: Characterize the distribution of power plant classes inside and outside DACs

Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default, 42 MMT, and 30 MMT

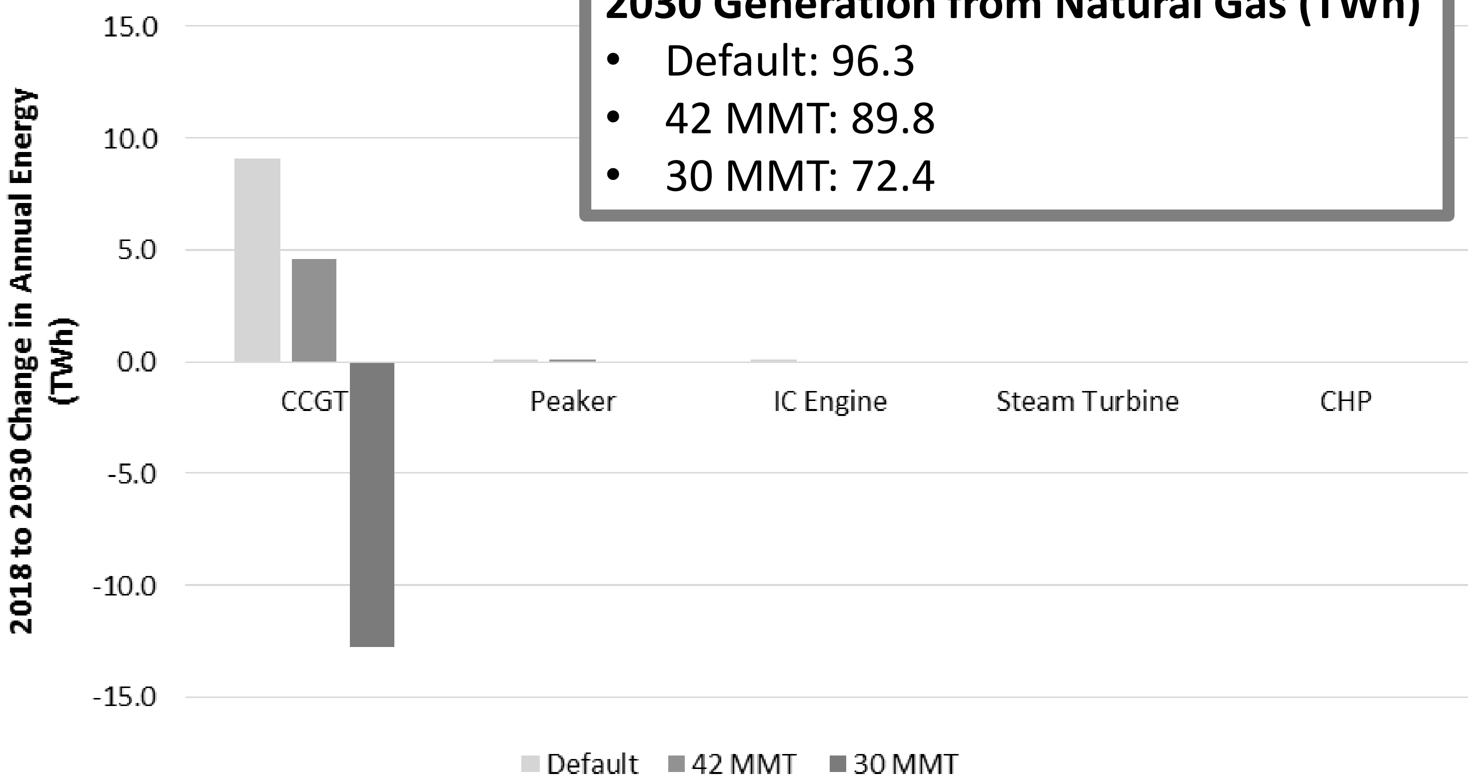
Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

Anticipated Change in Electricity Generation from Natural Gas Plants in California From 2018 to 2030

- Production changes most at CCGT plants
- The deemed GHG emissions factor that CARB assigns for imported electricity is larger than California CCGT emission factors , which can lead to more utilization of in-state generation and declining imports

2030 Generation from Natural Gas (TWh)

- Default: 96.3
- 42 MMT: 89.8
- 30 MMT: 72.4



Estimating Localized Air Pollutants

Air Pollutants Evaluated

- NOx and PM2.5

Analytical Method

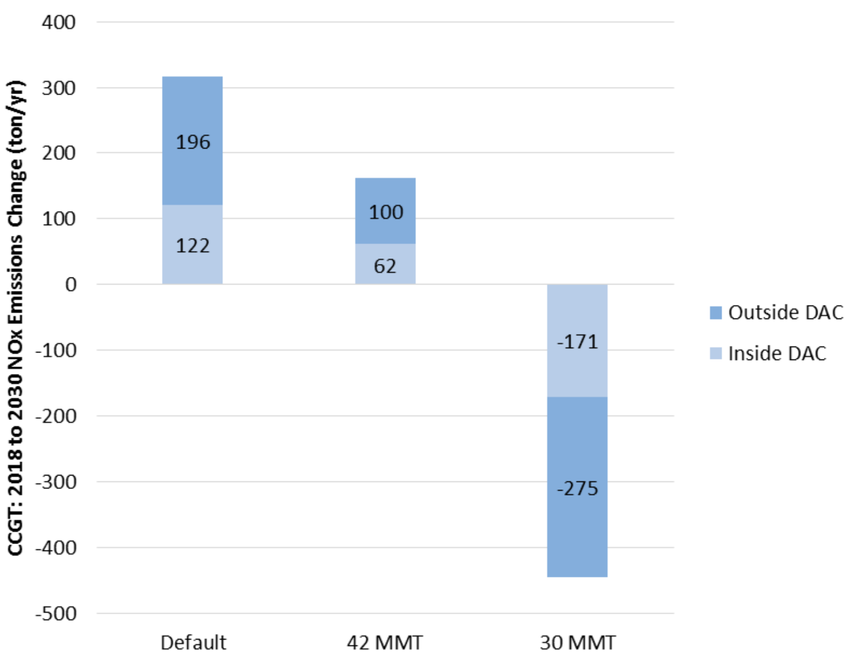
- Post-process RESOLVE results
  - RESOLVE provides annual production (MWh) and fuel consumption (MMBtu) for each natural gas plant type category
  - Apply appropriate emission factor to fuel use (lb/MWh or lb/MMBtu)
  - Note: RESOLVE does not forecast numbers of unit startups
- Greater air pollutant and GHG emission reductions result primarily from decreased use of CCGTs

Criteria Air Pollutant Emissions Factors and Geographic Distribution

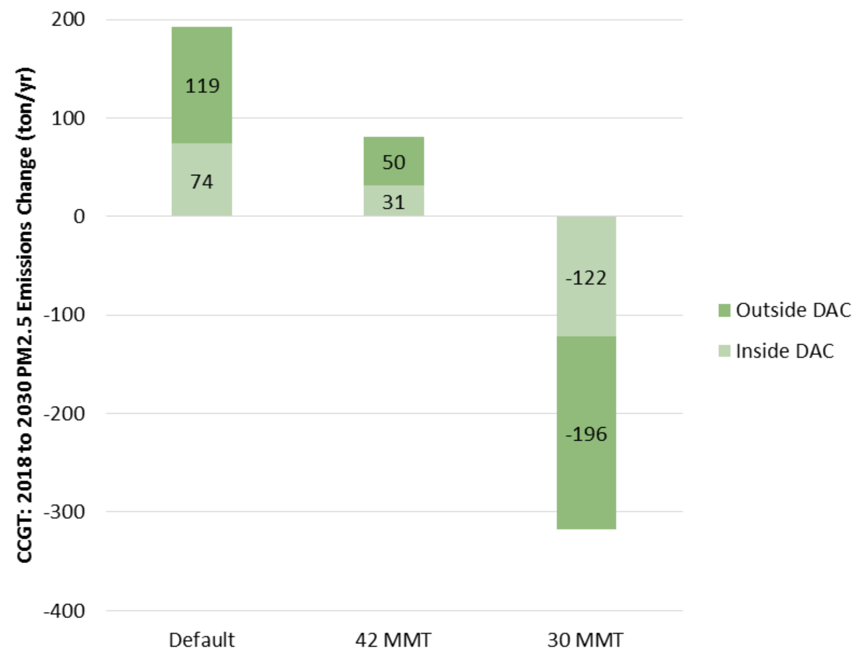
- Statewide emissions estimates use the following emission factors for these broad technology types
  - CCGT NOx: 0.07 lb/MWh; PM2.5: 0.0066 lb/MMBtu
  - Peaker NOx: 0.099-0.279 lb/MWh; PM2.5: 0.0066 lb/MMBtu
  - Data Sources:
    - CCGT and Peaker factors: *CEC Cost of Generation (2015) & USEPA AP-42*
    - Economy-wide emissions inventory projections for 2030: C*ARB CEPAM*
    - Motor vehicle fleet and average emissions for 2030: C*ARB EMFAC2014*
- Location of emissions were approximated based on distribution of installed MW for each technology

Change in CCGT Air Pollutants
Statewide between 2018 and 2030

- Cycling CCGTs will increase NOx during unit-startups (not included)
- PM2.5 is not notably influenced by numbers of startups
- Changes in emissions at CCGTs do not disproportionately affect DACs on average



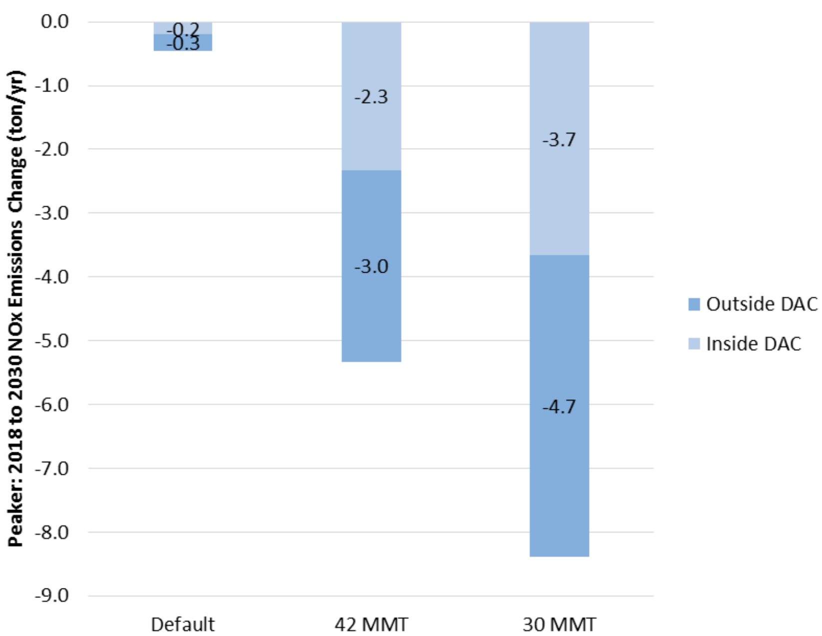
NOx



PM2.5

Change in Peaker Air Pollutants
Statewide between 2018 and 2030

- Potential emissions changes within the Peaker class of power plants are much smaller than those for CCGT class
- Changes in emissions at Peakers disproportionately affect DACs on average



NOx

PM2.5

Step 2 Conclusions

Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default, 42 MMT, and 30 MMT

- Fuel consumption and emissions changes within the CCGT class of power plants greatly outweigh those from the Peaker class

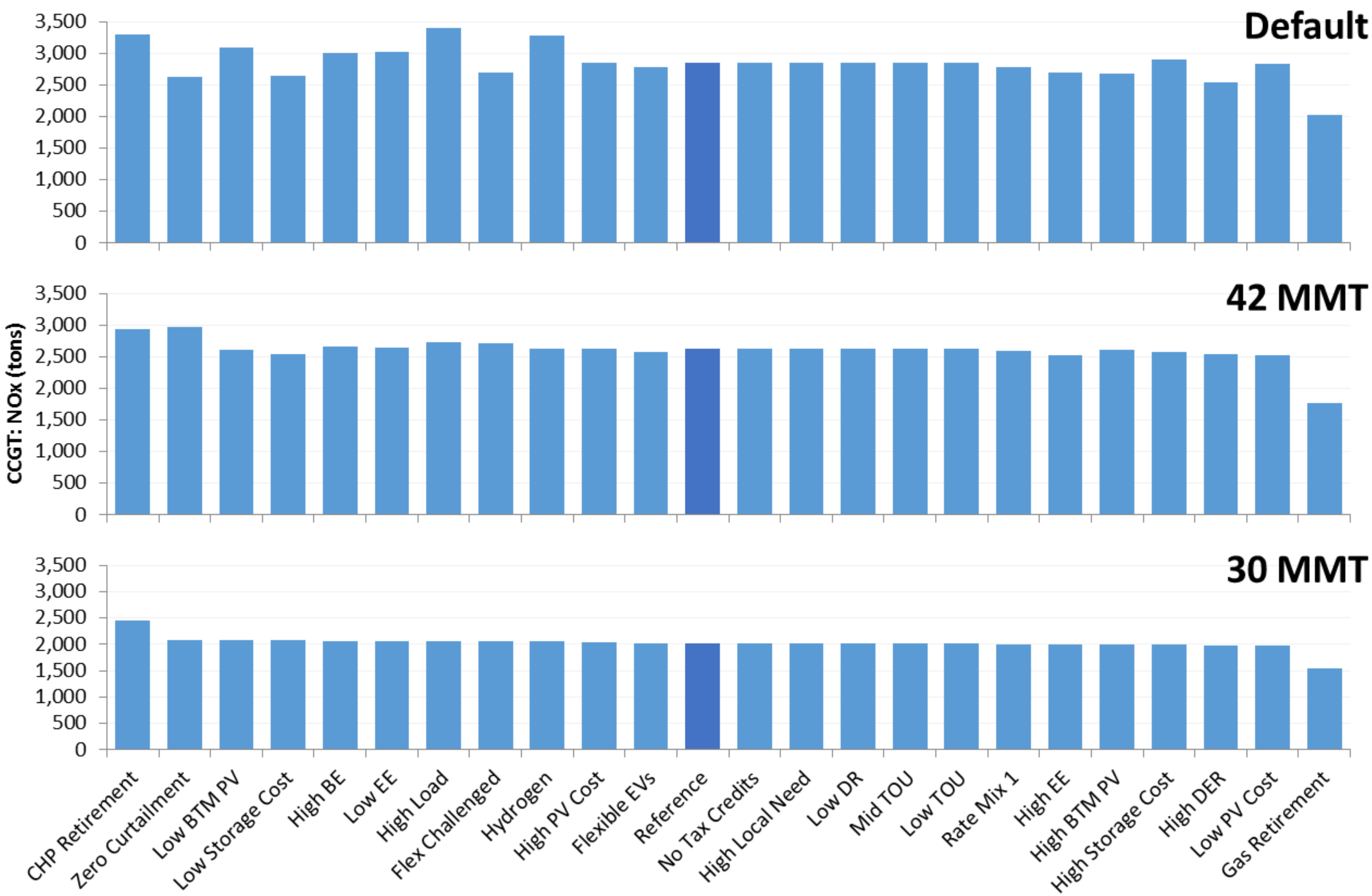
Approach

Step 1: Characterize the distribution of power plant class inside and outside DACs

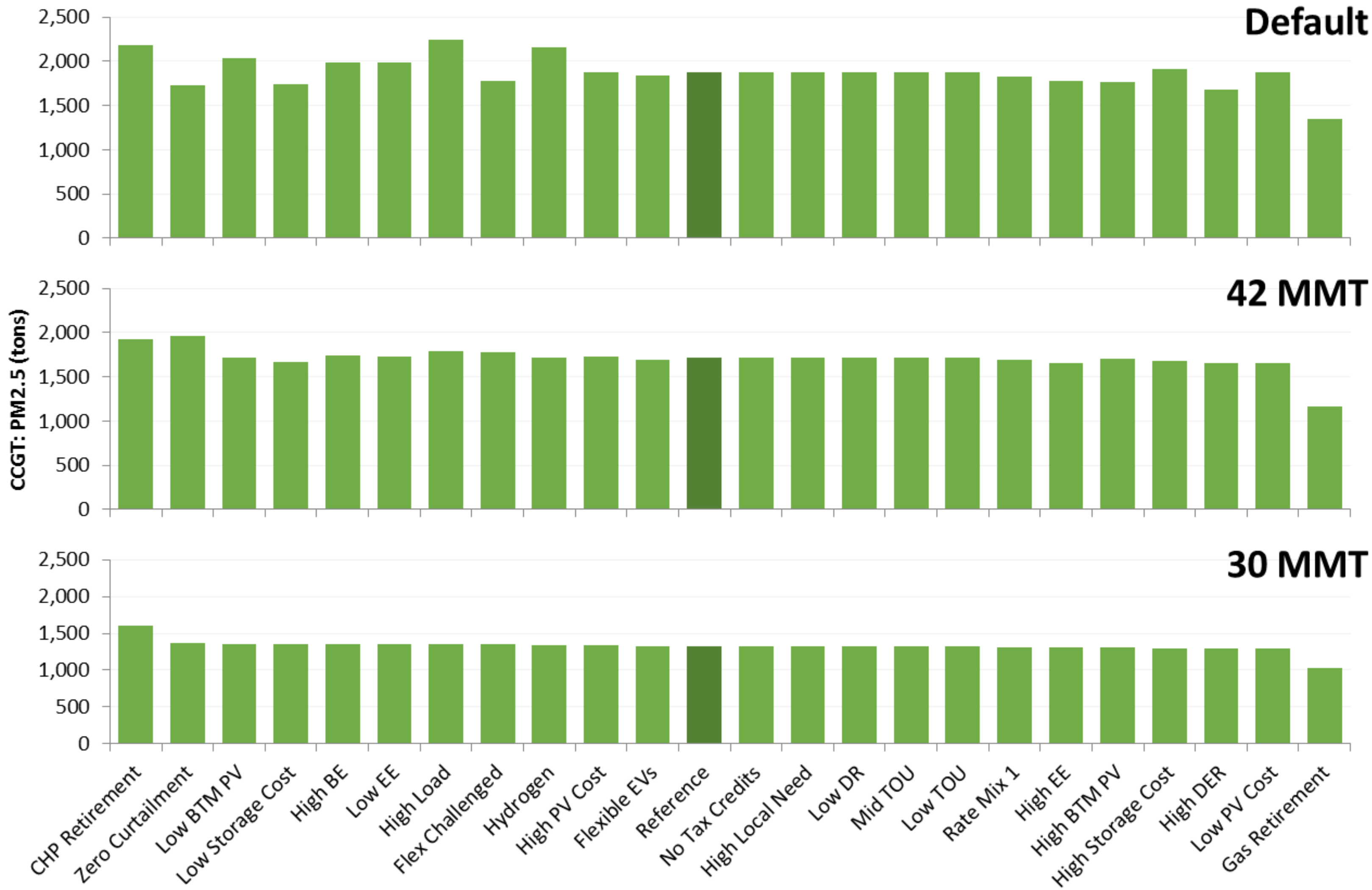
Step 2: Determine how fuel consumption and localized air pollutants change for each power plant class in the three core IRP cases: Default, 42 MMT, and 30 MMT

Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

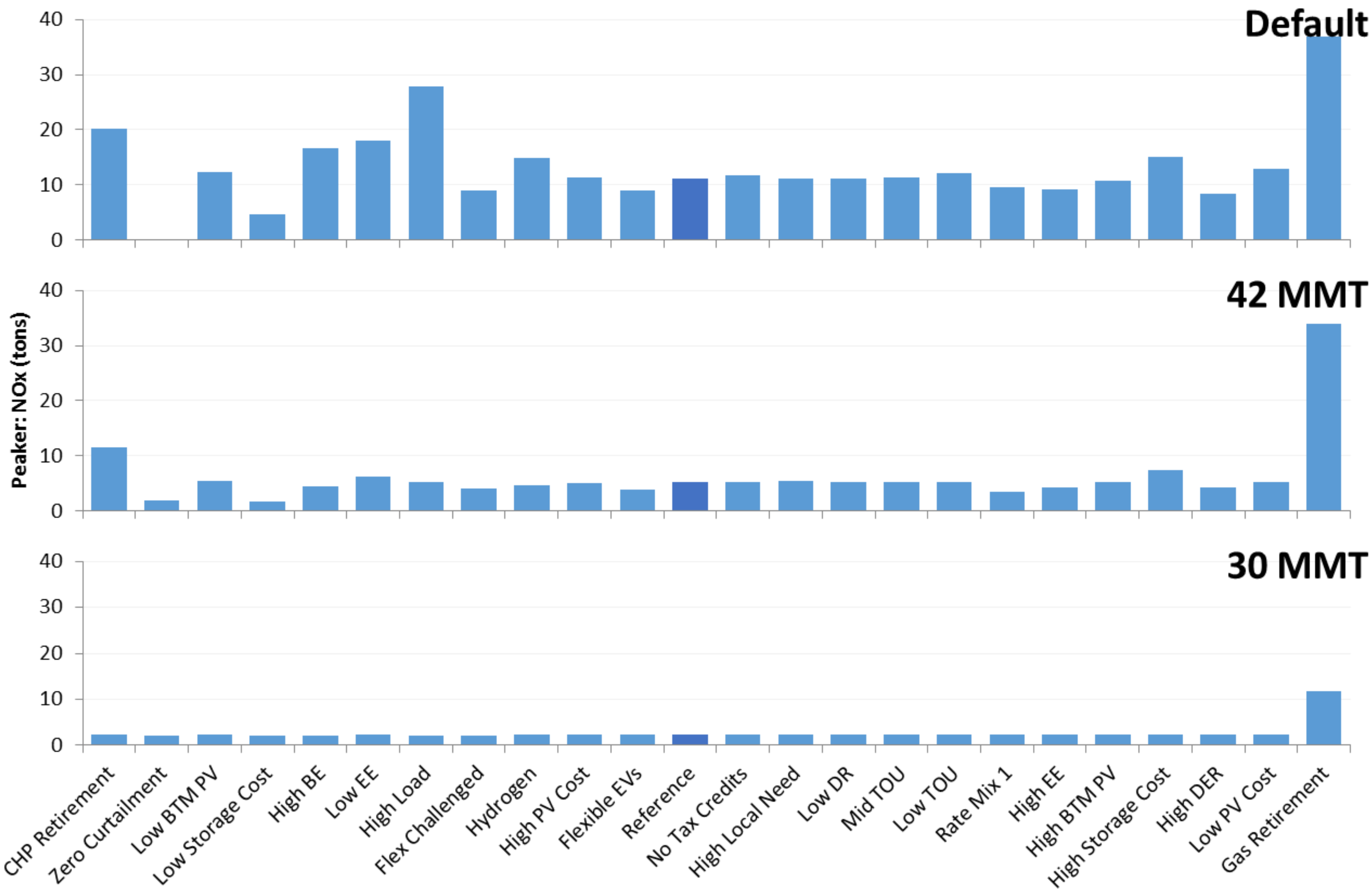
Statewide NOx from CCGTs Under Different GHG Targets in Optimal 2030 Portfolios (tons)



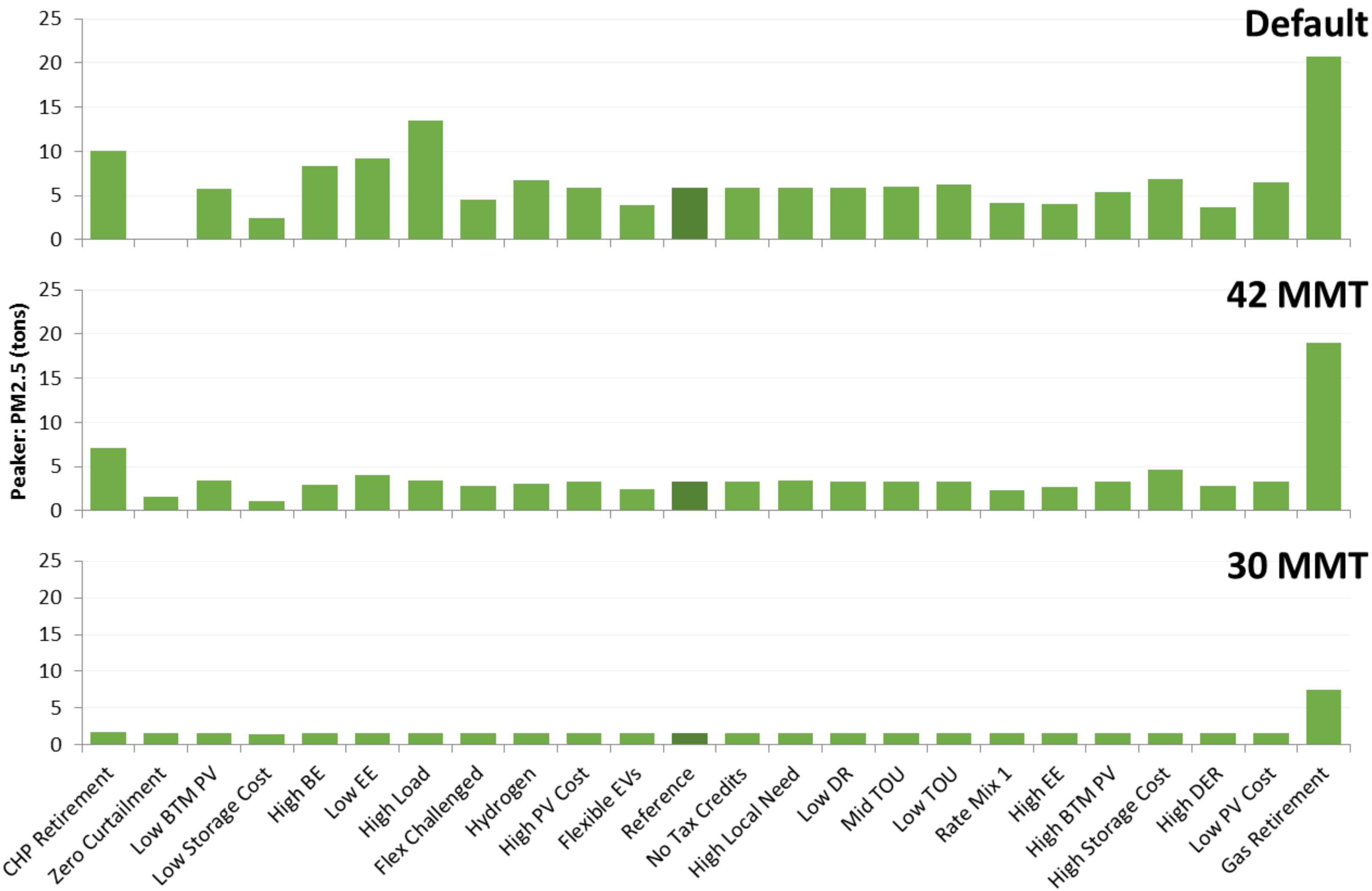
Statewide PM2.5 from CCGTs Under Different GHG Targets in Optimal 2030 Portfolios (tons)



Statewide NOx from Peakers Under Different GHG Targets in Optimal 2030 Portfolios (tons)

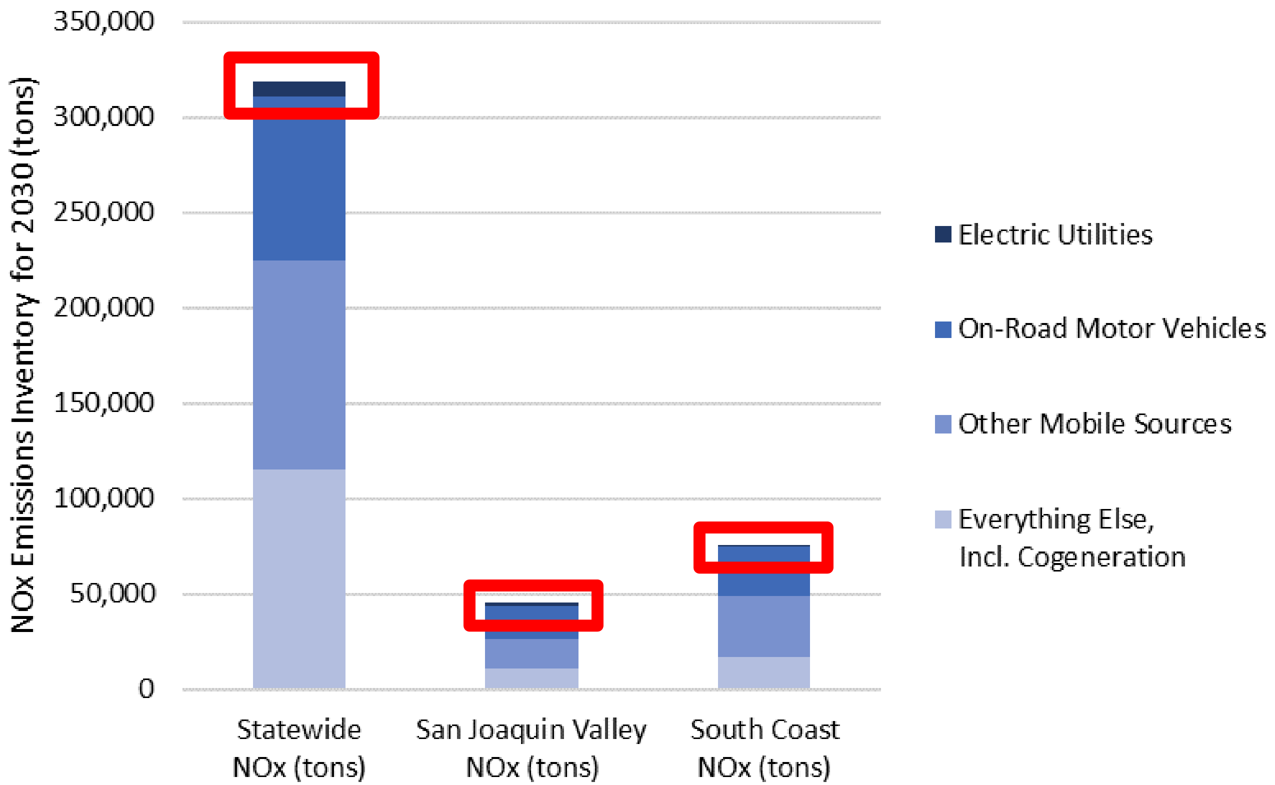


Statewide PM2.5 from Peakers Under Different GHG Targets in Optimal 2030 Portfolios (tons)



Contribution of NOx from Electricity Generation Compared with Mobile Sources

- Motor vehicles and other mobile sources create between 60-75% of overall NOx emissions, depending on location
- Electric utilities represent 2-4% of 2030 NOx emissions



"California Emissions Projection Analysis Model" which is an online tool at: https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php

Contribution of PM2.4 from Electricity Generation Compared with Mobile Sources

- Motor vehicles and other mobile sources create between 12-22% of overall PM2.5 emissions, depending on location
- Electric utilities represent 1-2% of 2030 PM2.5 emissions

"California Emissions Projection Analysis Model" which is an online tool at: https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php

Step 3 Conclusions

Step 3: Determine how localized air pollutants change across a range of IRP sensitivities for the power plants that most impact DACs

- The overall GHG target generally has a larger impact than individual sensitivities on the level of localized air pollutants
- Factors that increase load tend to increase localized air pollutant emissions from power plants and vice versa
- Power plants are a small contributor to statewide NOx and PM2.5 levels relative to other sources of pollution

Overall Conclusion

- Reducing CCGT use as part of a plan to achieve a GHG planning target (e.g., 42 MMT) achieves the greatest quantities of reductions in localized air pollutants, including in DACs

A.2. RENEWABLE ENERGY DEVELOPMENT IN DISADVANTAGED COMMUNITIES

Incremental Renewable Resource Buildout in Disadvantaged Communities

Statutory Goal for IRP

- "Strengthen the diversity, sustainability, and resilience … of local communities"

Analytical Goal

- Characterize the amount of new renewable resource buildout likely to occur in disadvantaged communities

Zones Analyzed

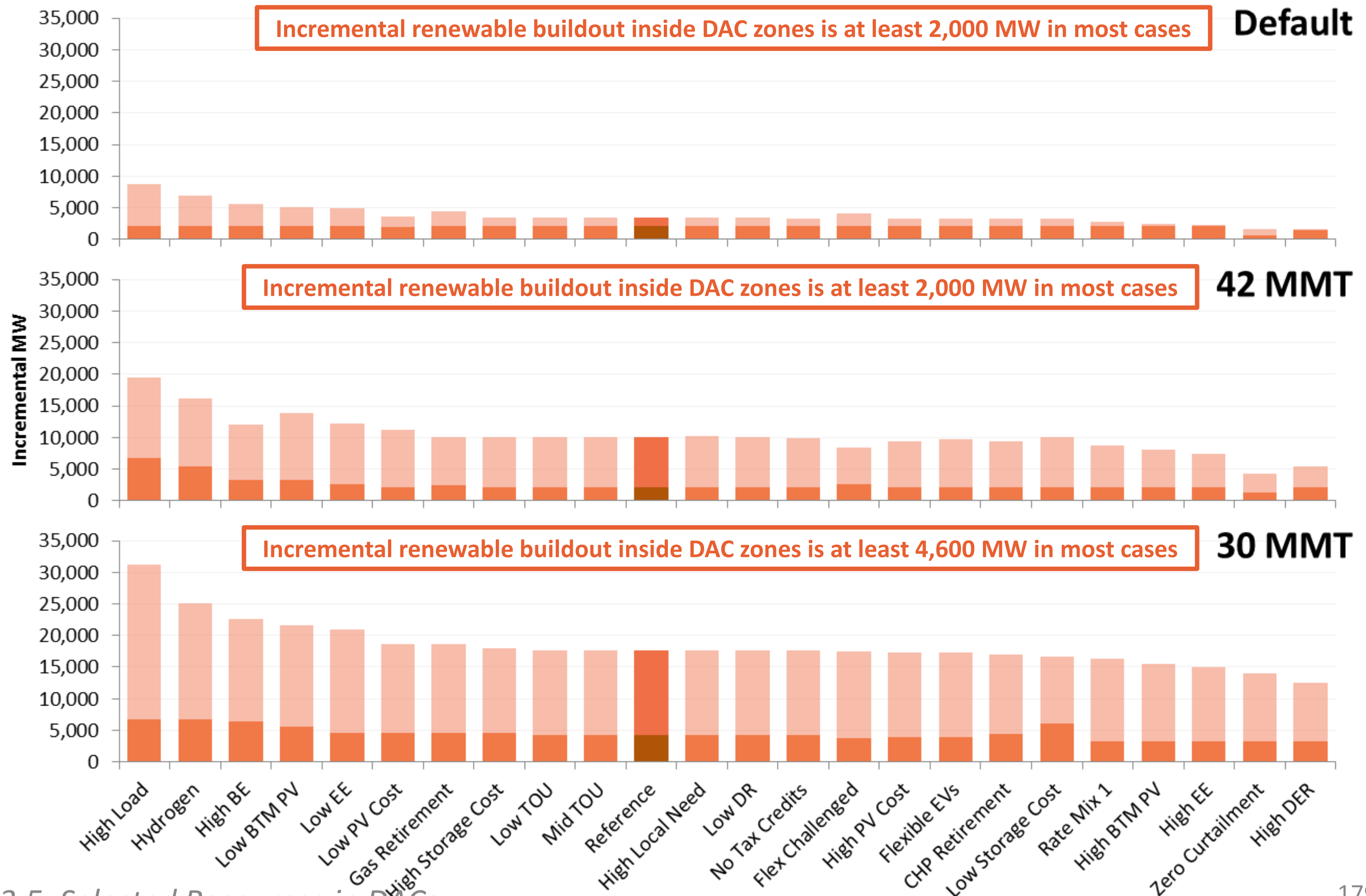
- Renewable resources zones used in RESOLVE are geographic zones that can span multiple counties or substantial portions of counties
- Resource zones originally evolved from Competitive Renewable Energy Zone (CREZ) boundaries
  - **Four** renewable resource zones in RESOLVE have 25% or more of their population in disadvantaged communities:
    - Central Valley North & Los Banos
    - Westlands
    - Kramer & Inyokern
    - Greater Imperial

Guide to Charts Presented in this Section

- The slide that follows shows bar charts that depict the total quantities of incremental resources (such as solar PV, wind, geothermal energy, and pumped storage) selected across a range of sensitivities that reflect different possible future conditions (see Appendix B for more detail on how each sensitivity is defined)
- Each bar depicts two pieces of information:
  - The larger, lighter color shows the total quantity of resources selected in that sensitivity
  - The smaller, darker color shows the quantity if resources in any of the four zones with 25% or more of their population in disadvantaged communities

RESOLVE Output: Selected Resources

in Four Resource Zones Characterized by Disadvantaged Communities



Conclusions

- The more stringent the GHG target, the more renewable energy development in DACs
- Greater ZEV adoption and greater building electrification increases load, leading to more utility-scale renewable energy development in DACs
- Greater adoption of BTM PV and EE decreases load, leading to less utility-scale renewable energy development in DACs

APPENDIX B
SENSITIVITY ANALYSIS

Sensitivity Analysis

- The following slides show a series of sensitivities that present the portfolio composition and incremental cost impacts of different assumptions for each core policy case (Default, 42 MMT, and 30 MMT) about:
  - the achievement level for different resource goals and programs (such as adoption of energy efficiency);
  - the costs of different resources (such as battery storage); and
  - other future conditions (such as lower than expected grid flexibility)
- The sensitivities are intended to help decision makers evaluate:
  - the potential costs of pursuing different resource policies;
  - how costs change depending on the GHG emissions target; and
  - how costs change depending on different future conditions that may be outside of CPUC control.

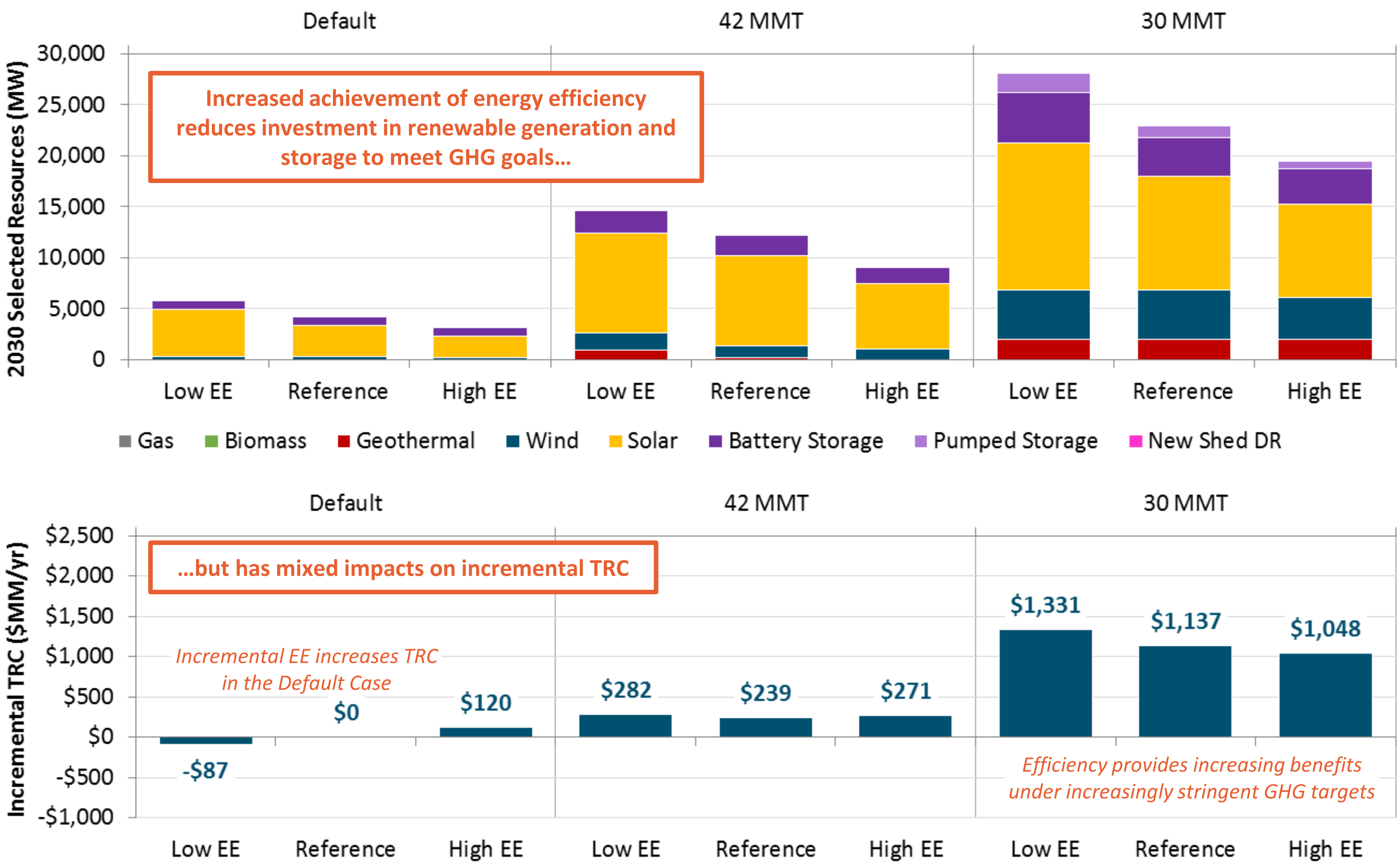
Overview of Sensitivities

Sensitivity	Description
Reference	**Reference Case**
High EE	Increased adoption of EE, consistent with **SB350 EE doubling goal**
Low EE	Decreased adoption of efficiency, consistent with **CEC 2016 IEPR Mid AAEE projection**
High BTM PV	Increased adoption of BTM, corresponding to cumulative adoptions of **21 GW by 2030**
Low BTM PV	Decreased adoption of BTM, corresponding to cumulative adoptions of **9 GW by 2030**
Flexible EVs	All new electric vehicle loads treated as flexible within the day (load can be shifted between hours subject to constraints on vehicle availability)
High PV Cost	High projections of future solar PV cost
Low PV Cost	Low projections of future solar PV cost
High Battery Cost	High projections of current & future battery storage costs
Low Battery Cost	Low projections of current & future battery storage costs
No Tax Credits	All new renewables assumed to be developed assuming no **long-term federal tax credits** (no PTC; 10% ITC for solar PV)
Gas Retirements	An additional **12.7 GW of gas generation assumed retire by 2030**, reducing gas fleet to 13 GW

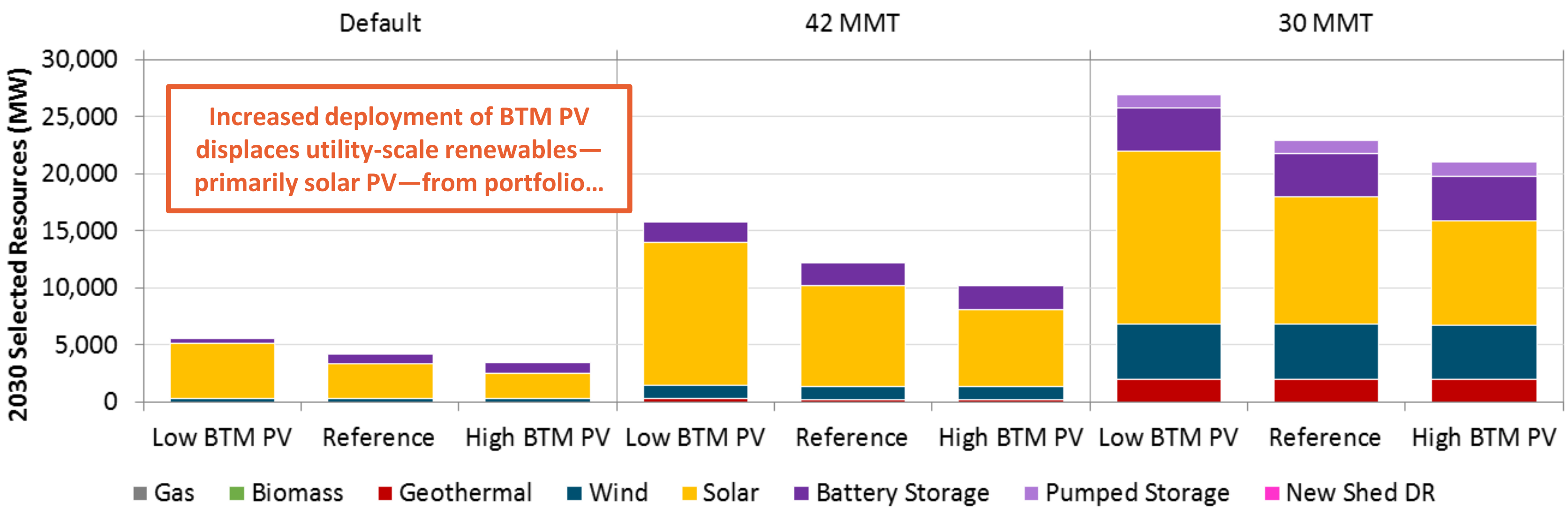
Overview of Sensitivities

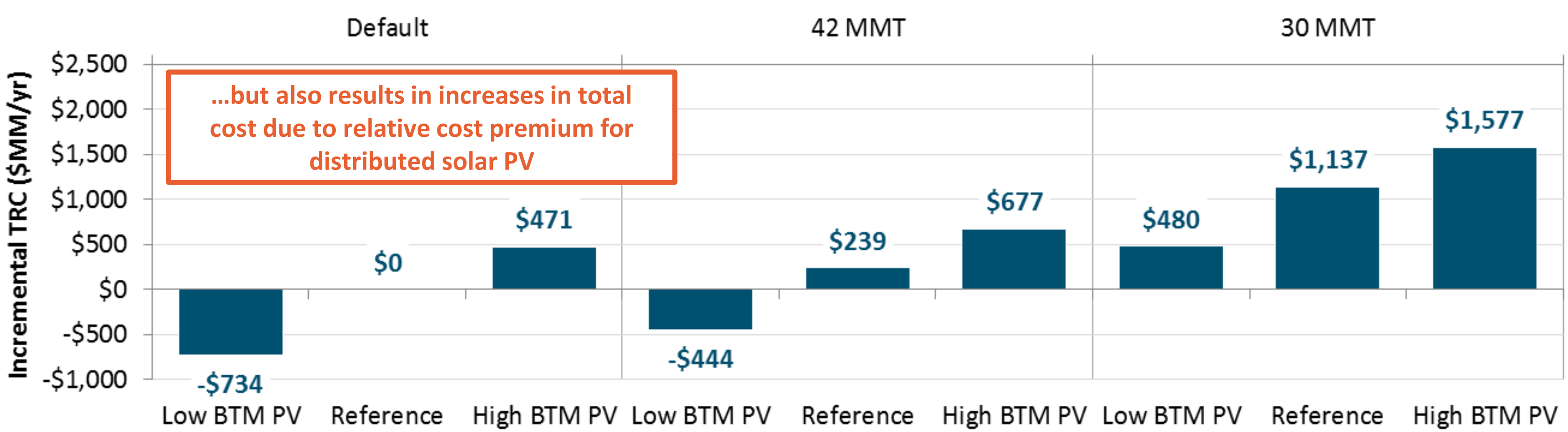
Sensitivity	Description
Reference	**Reference Case**
CHP Retirement	All existing non-dispatchable CHP **(1,600 MW)** assumed to retire by 2030
Flex Challenged	Combines a low net export constraint **(2,000 MW)** with a minimum gas generation requirement **(2,000 MW)**
High Load	Combines Low BTM PV, Low EE, High Building Electrification, and High EV sensitivities
High Local Need	Assumes hypothetical local LCR needs of **1,500 MW** by 2026
Low DR	Assumes discontinuation of existing economically dispatched DR programs after 2022
Low TOU	Low level of TOU rate impacts (based on Christensen Scenario 3)
Mid TOU	Mid level of TOU rate impacts (based on MRW Scenario 4)
Rate Mix 1	Captures a load impact consistent with rate designs modeled in LBNL Rate Mix 1 **(1-2% load reduction)**
Zero Curtailment	Prohibits renewable curtailment in day-to-day operations of the grid as an integration solution
High DER	Assumes high levels of all DERs, including BTM PV, ZEVs, EE, and DR

Energy Efficiency Sensitivities: Summary Results from RESOLVE

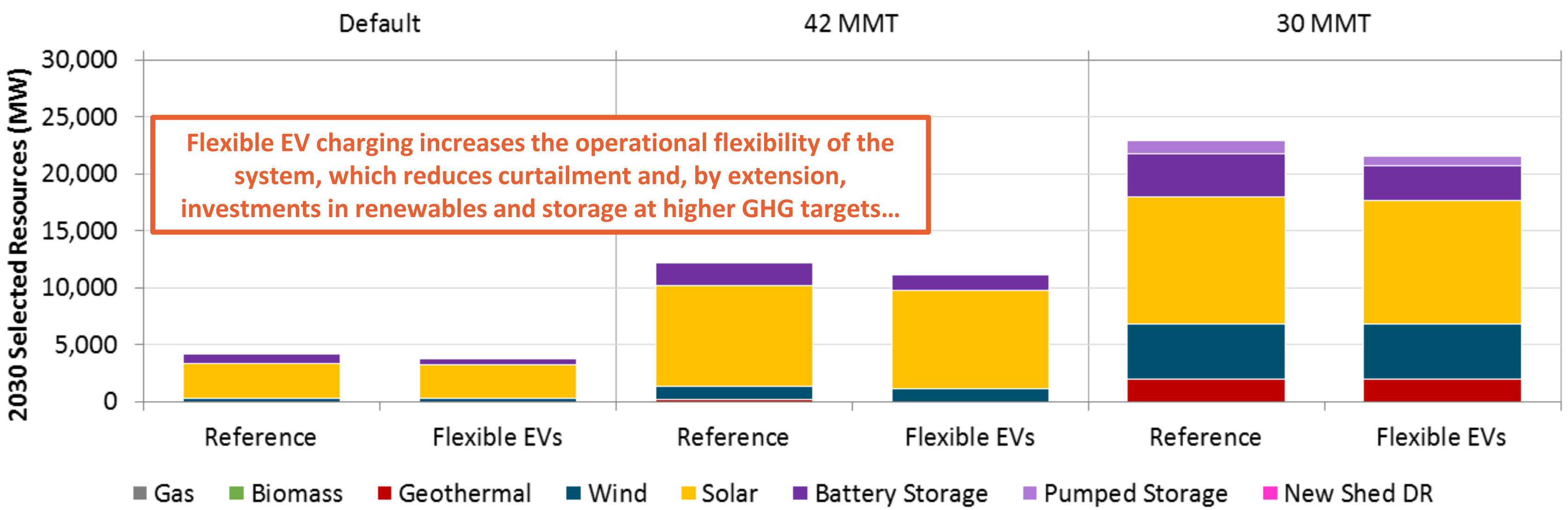


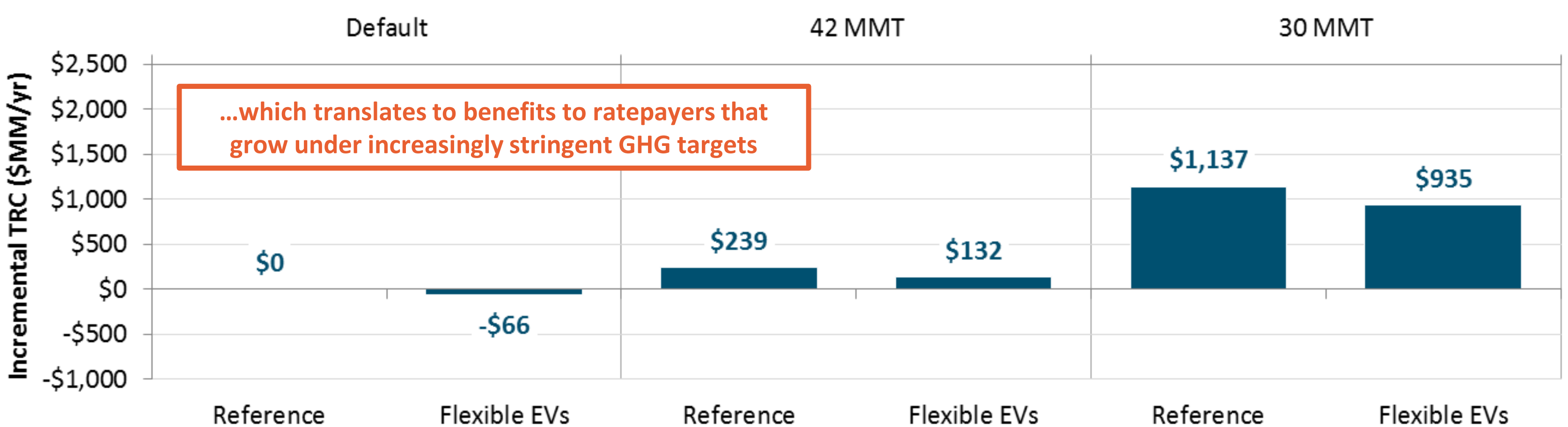
BTM PV Sensitivities: Summary Results from RESOLVE



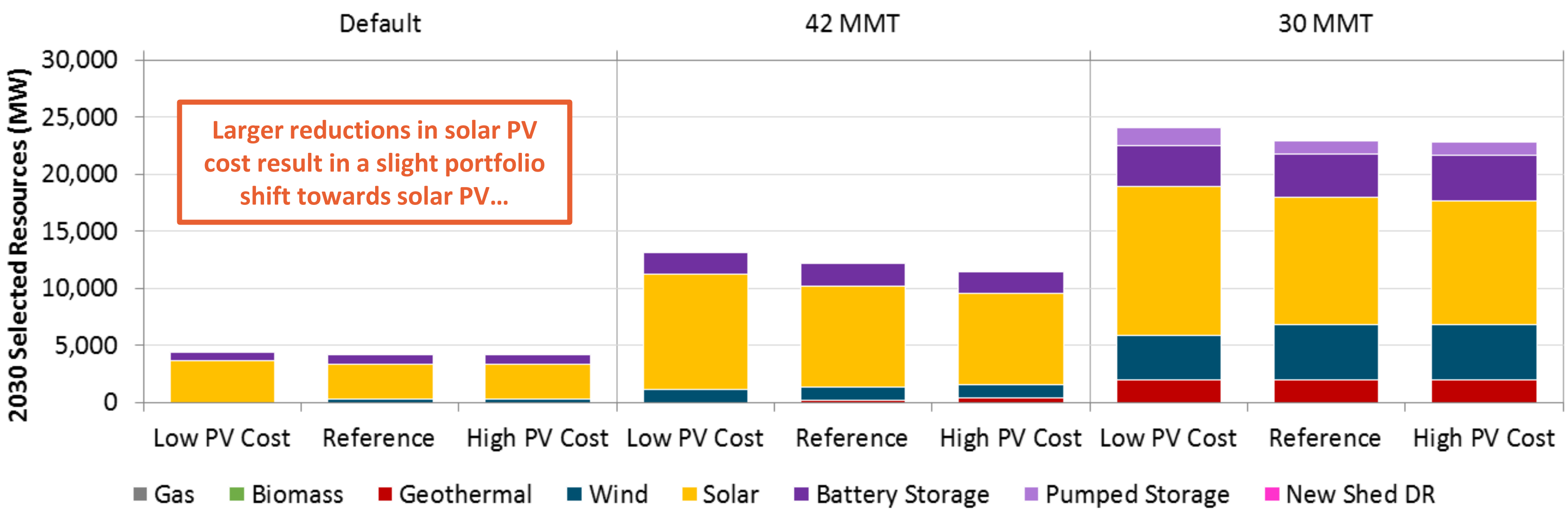


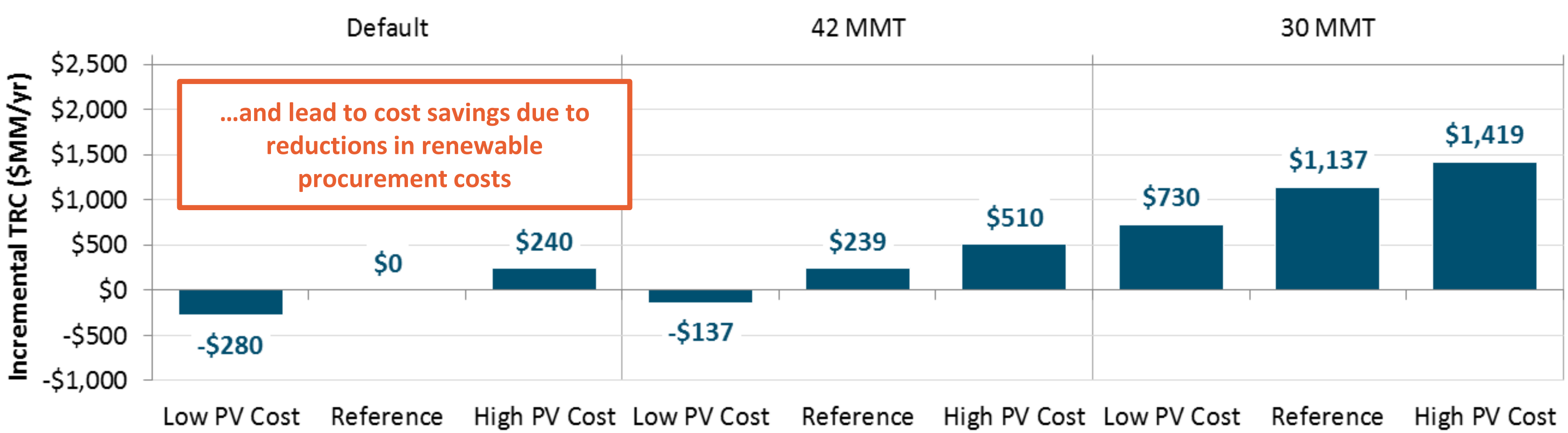
Flexible EV Sensitivity: Summary Results from RESOLVE



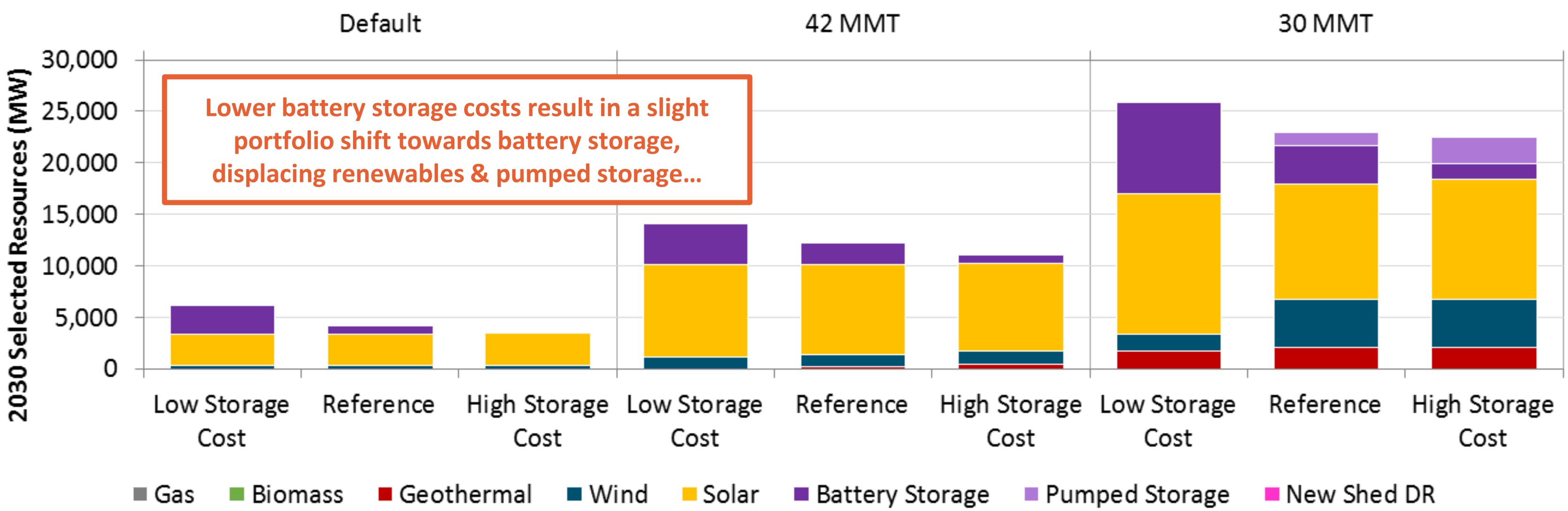


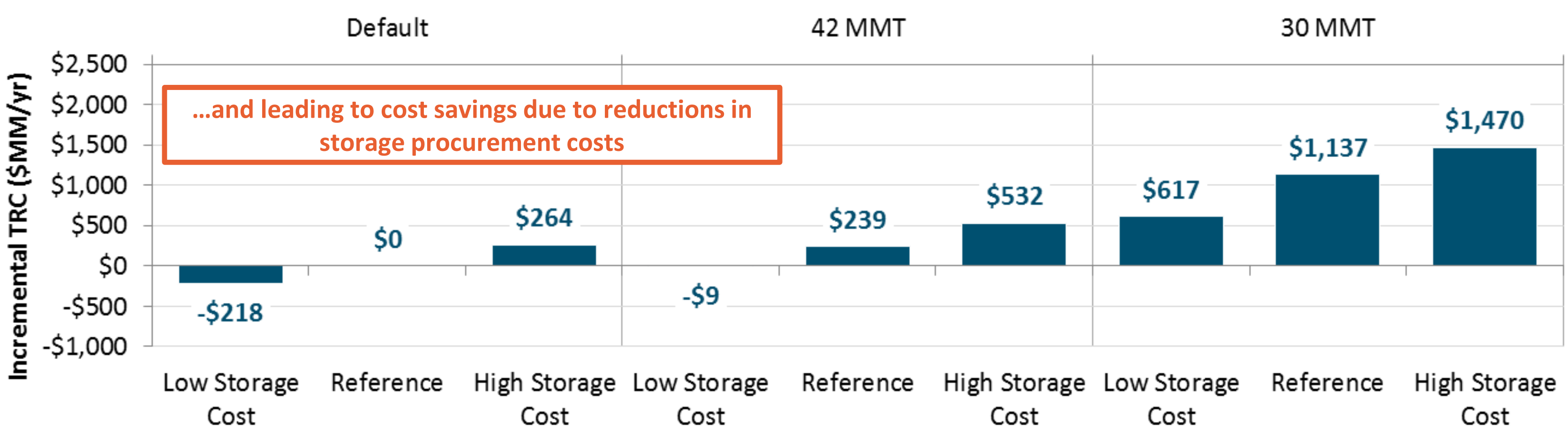
Solar PV Cost Sensitivities: Summary Results from RESOLVE



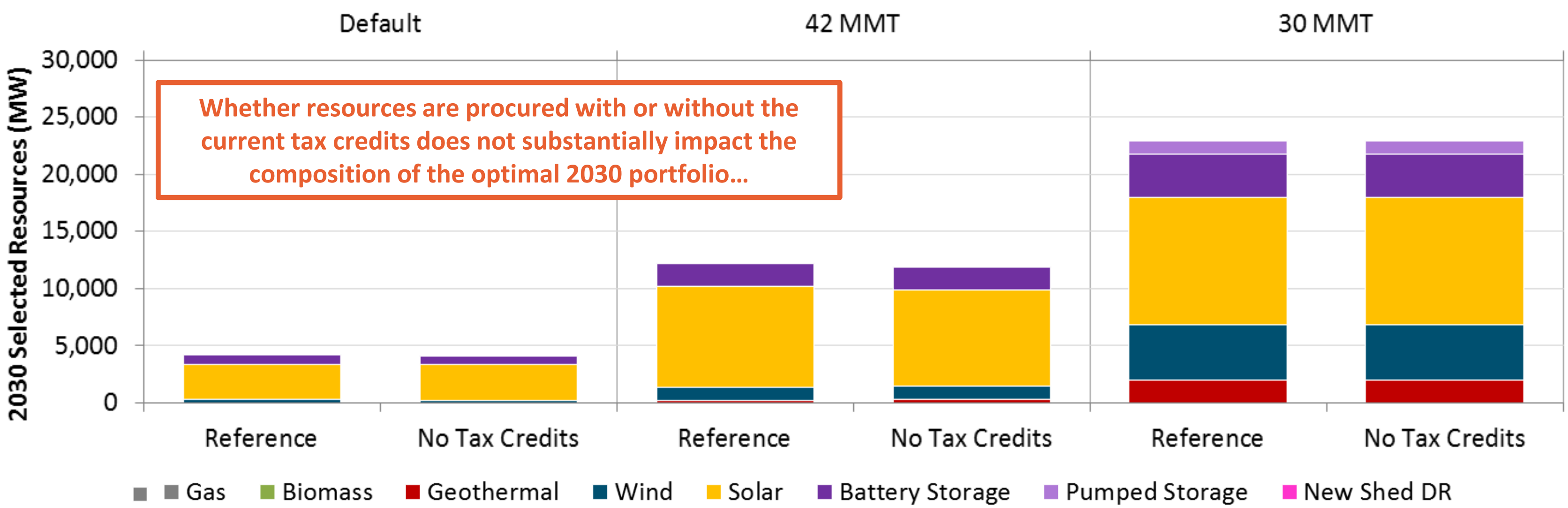


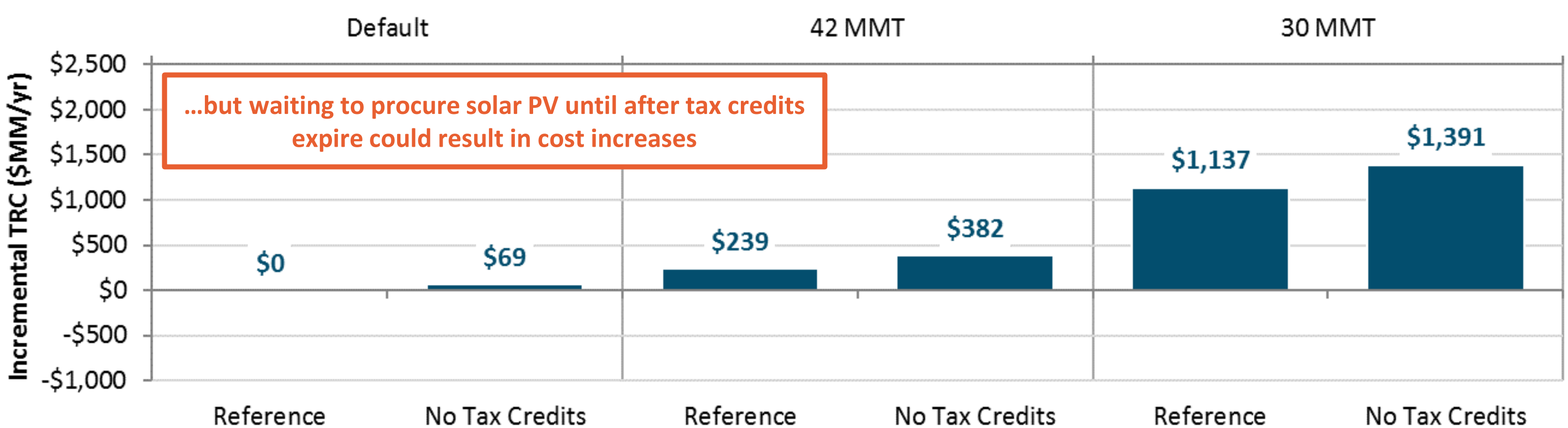
Battery Storage Cost Sensitivities: Summary Results from RESOLVE



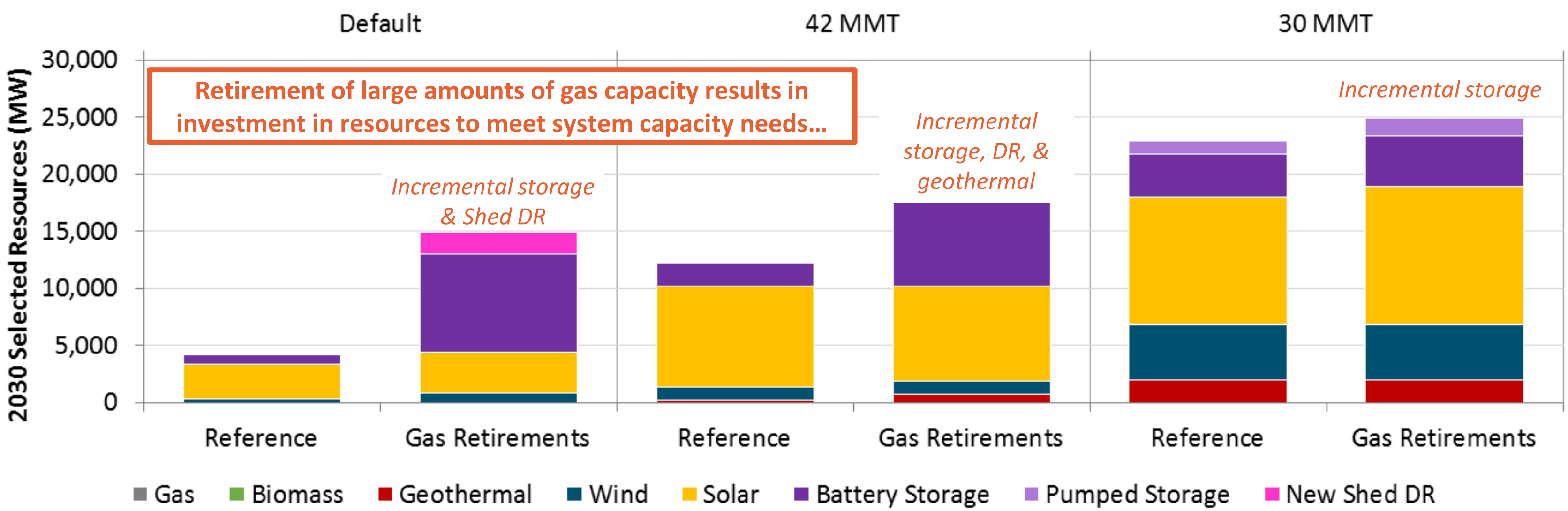


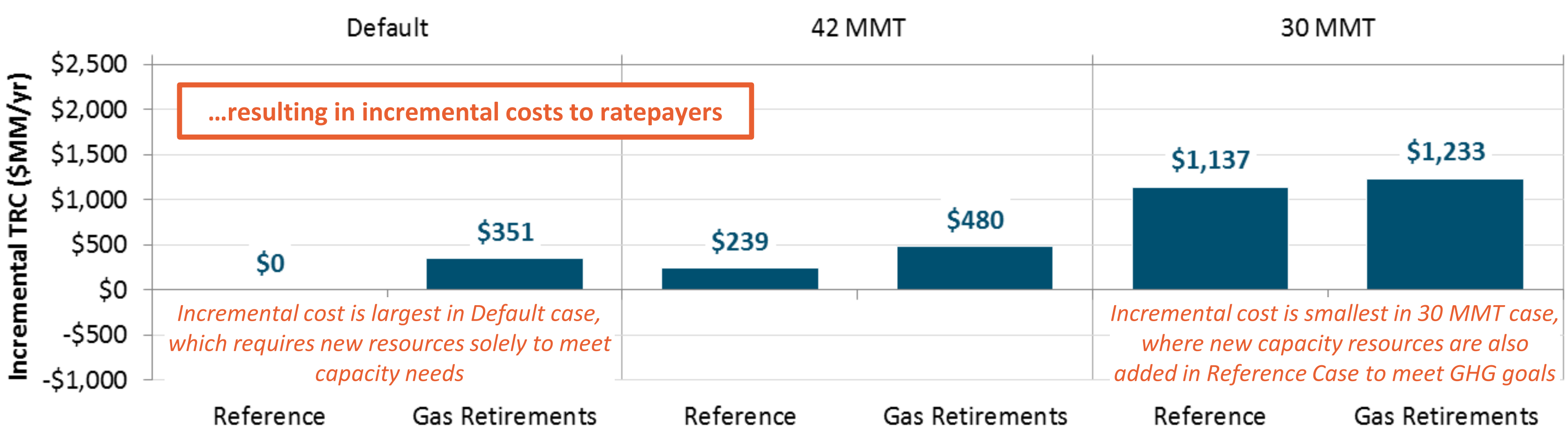
No Tax Credits Sensitivity: Summary Results from RESOLVE



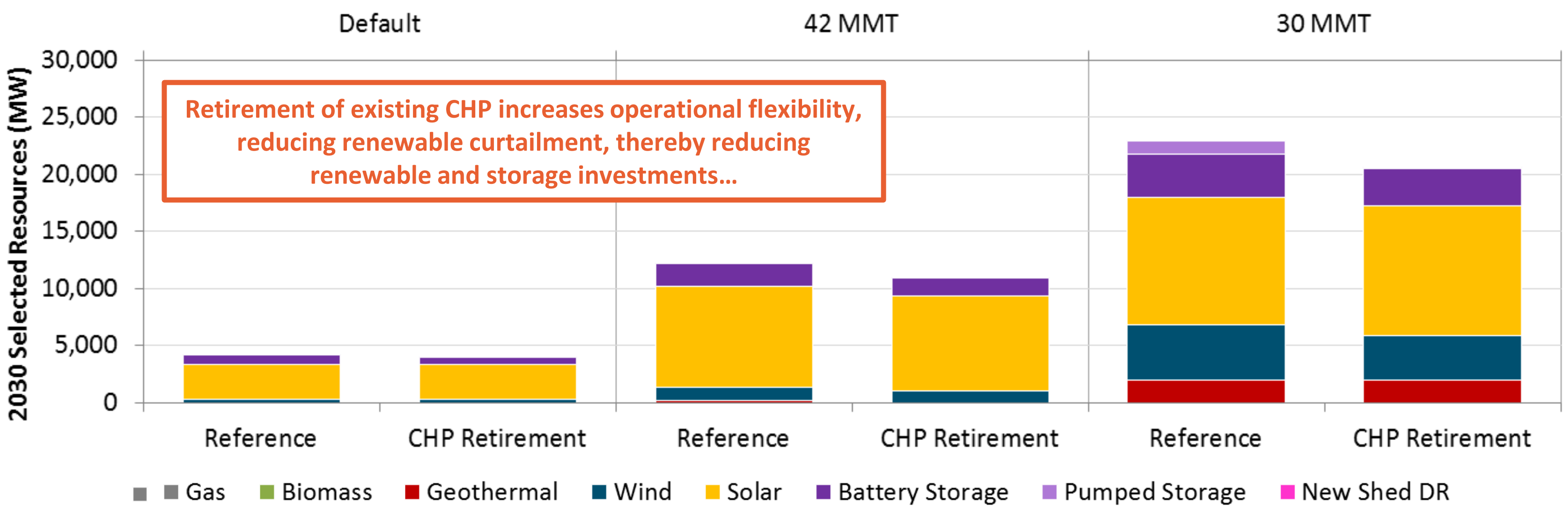


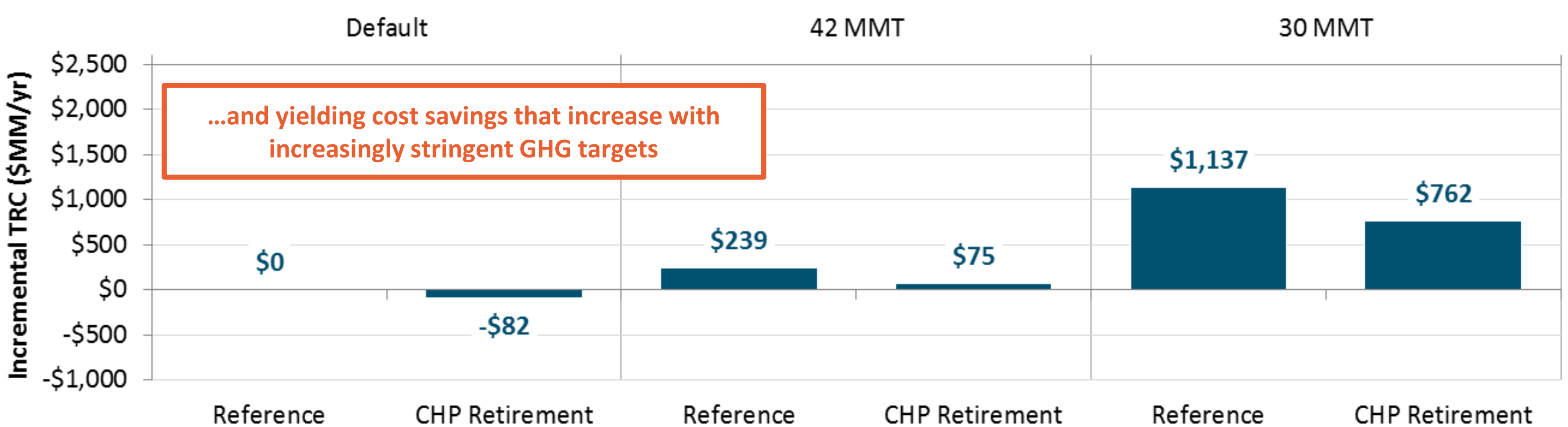
Gas Retirements Sensitivity: Summary Results from RESOLVE



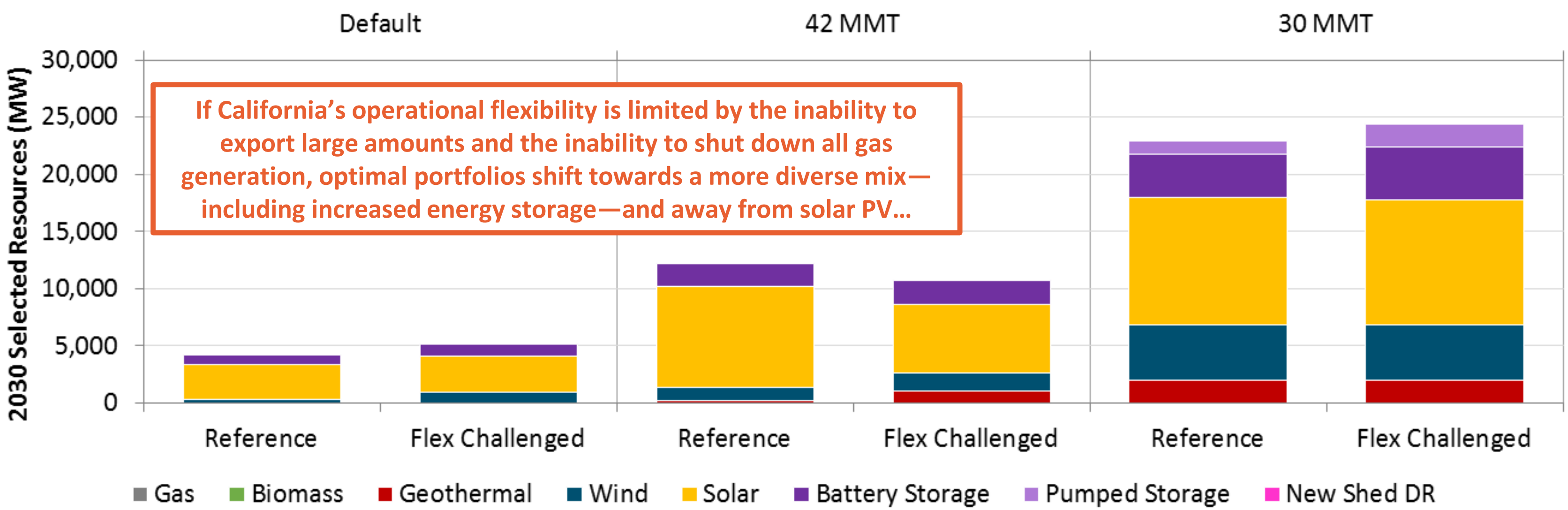


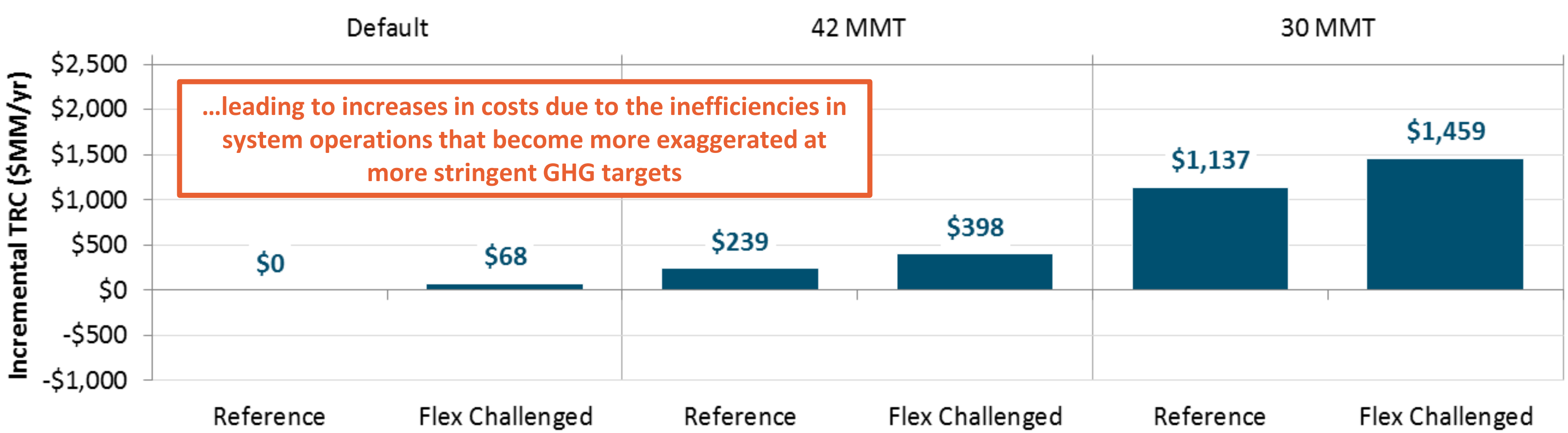
CHP Retirements Sensitivity: Summary Results from RESOLVE



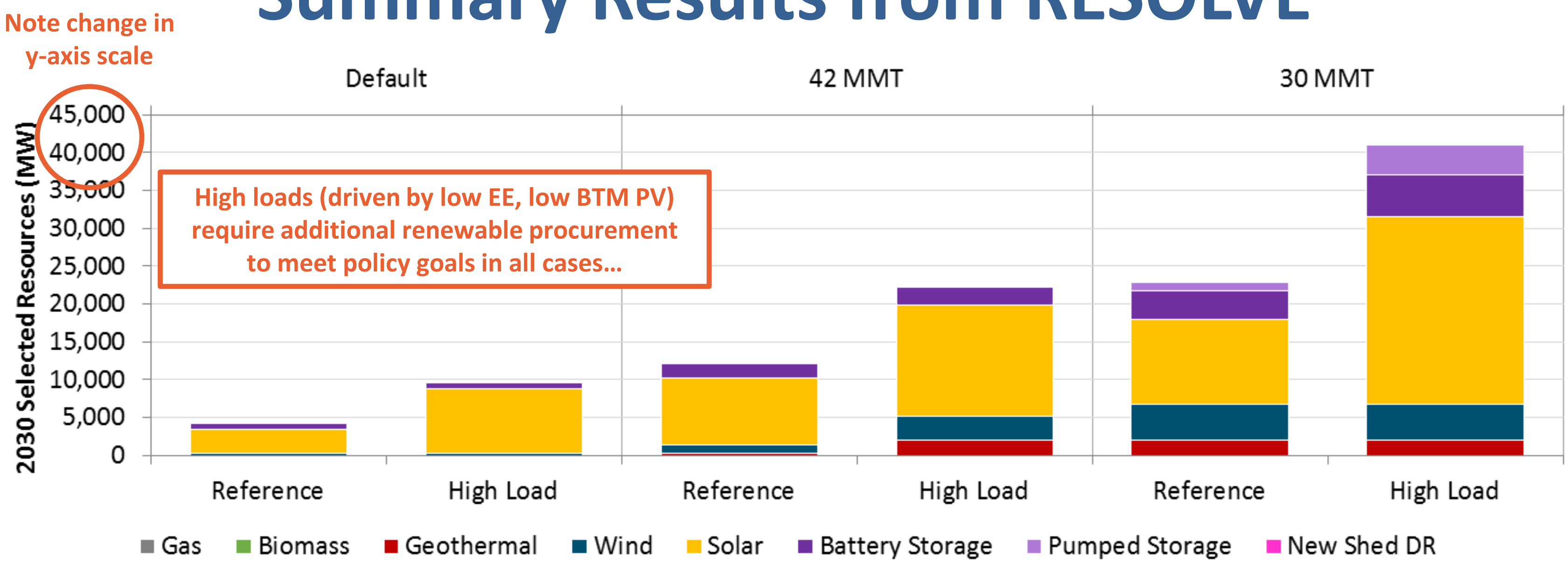


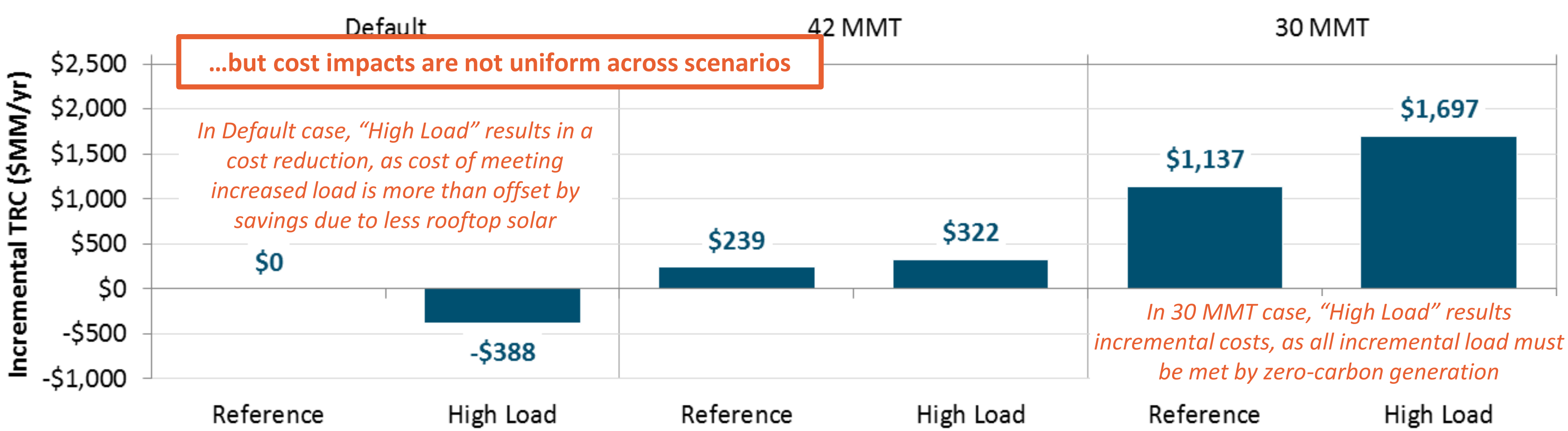
Flexibility Challenged Sensitivity: Summary Results from RESOLVE



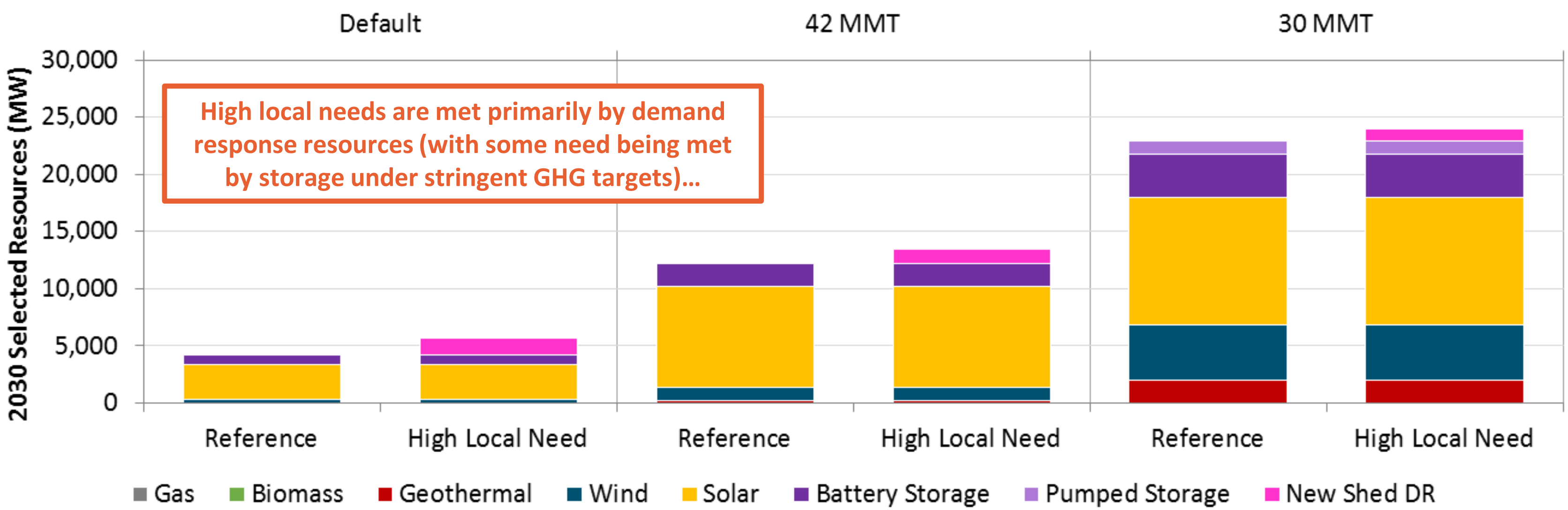


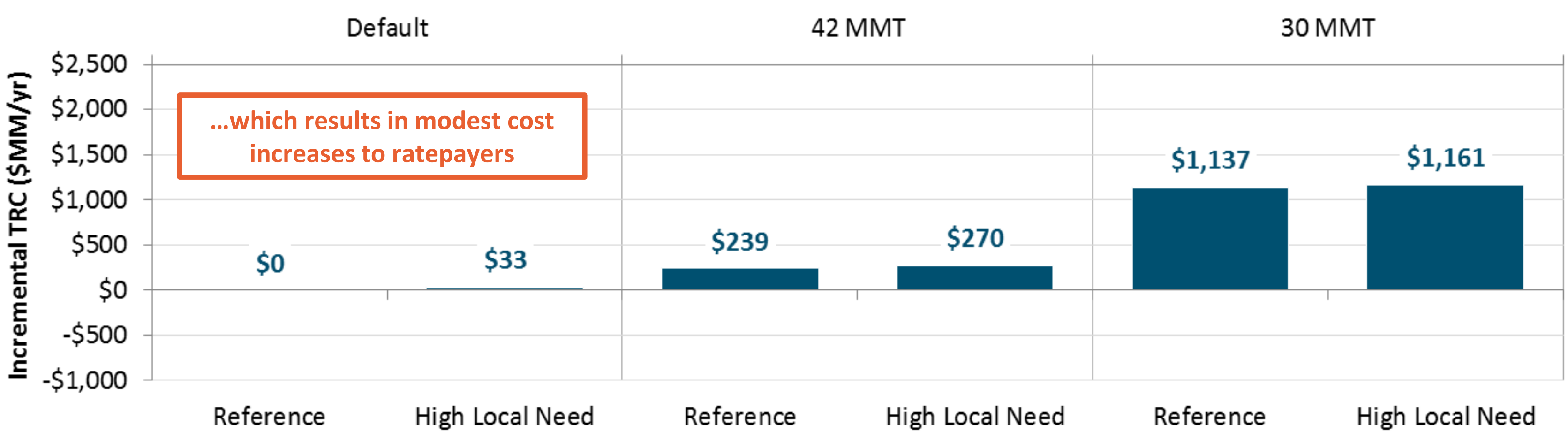
High Load Sensitivity: Summary Results from RESOLVE



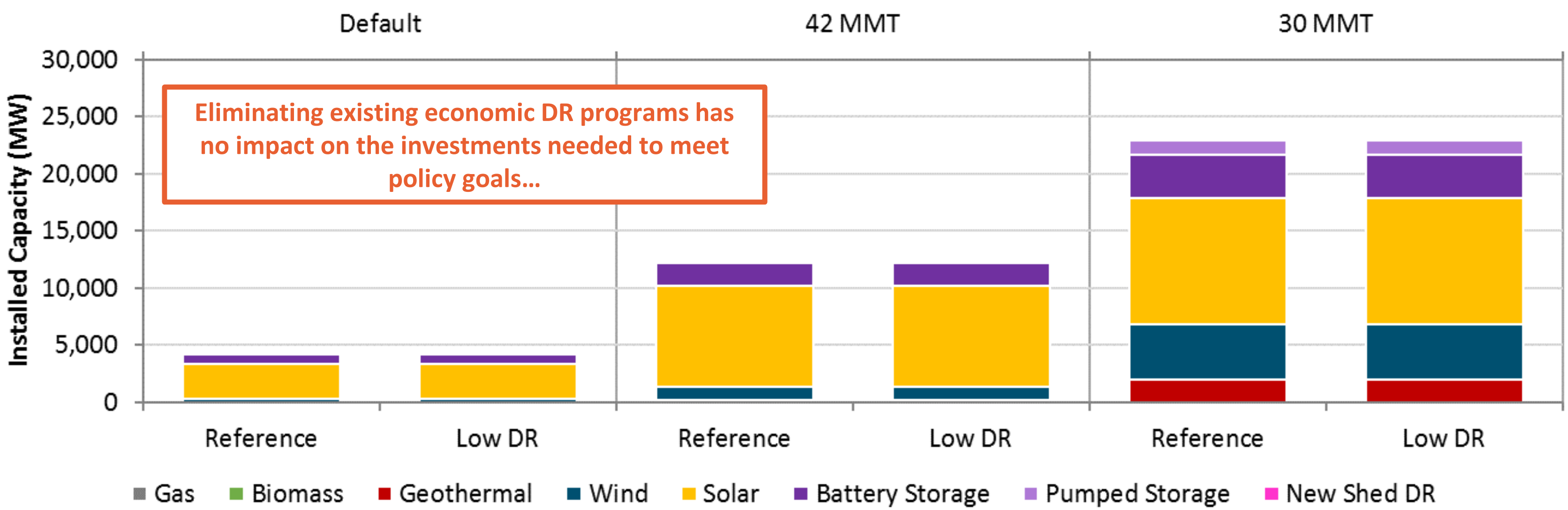


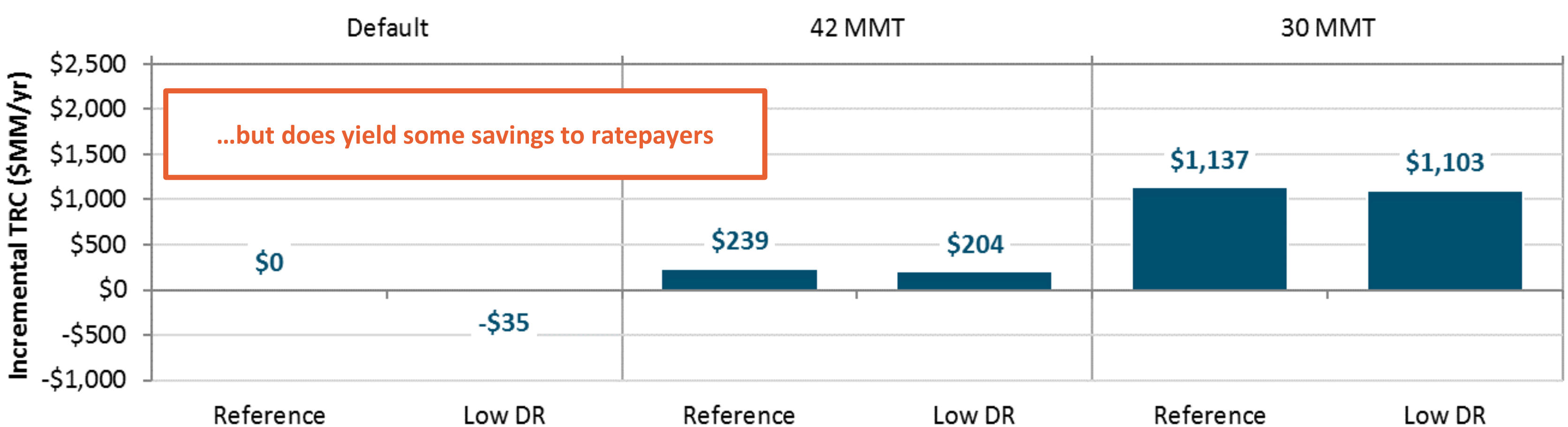
High Local Needs Sensitivity: Summary Results from RESOLVE



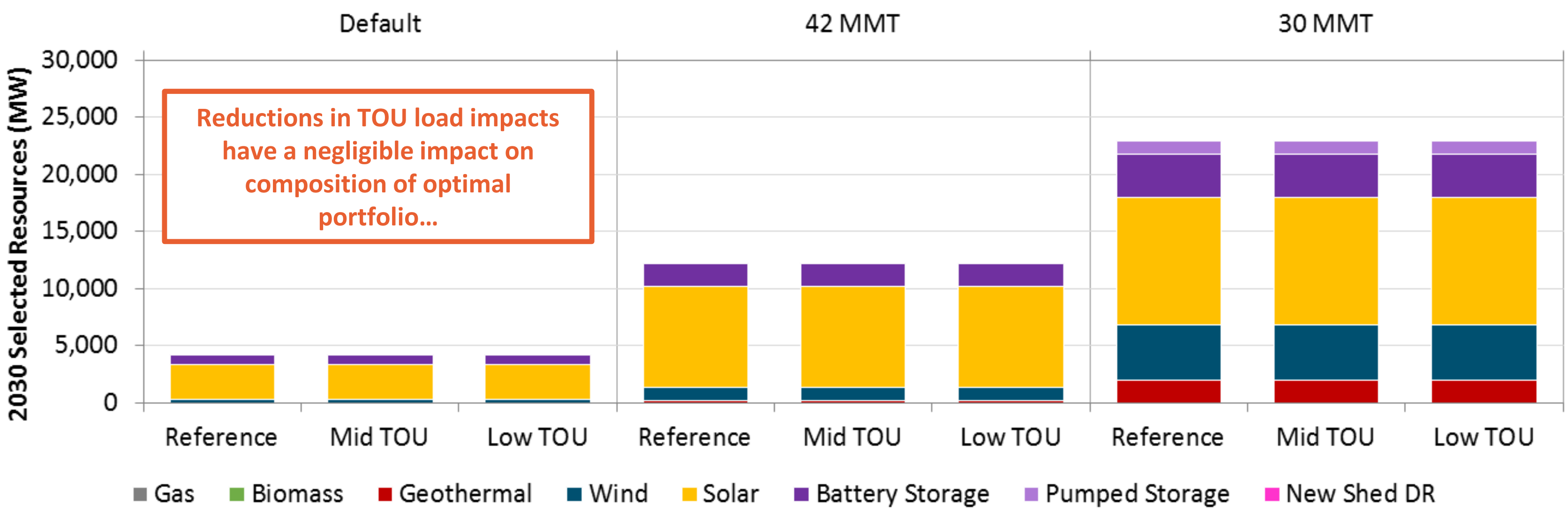


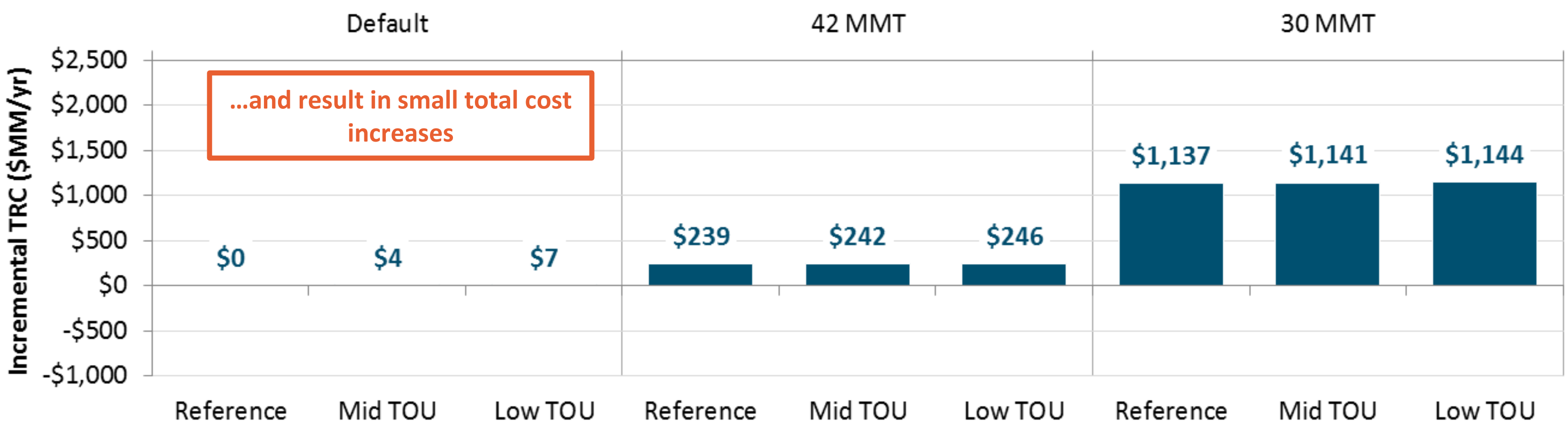
Low DR Sensitivity: Summary Results



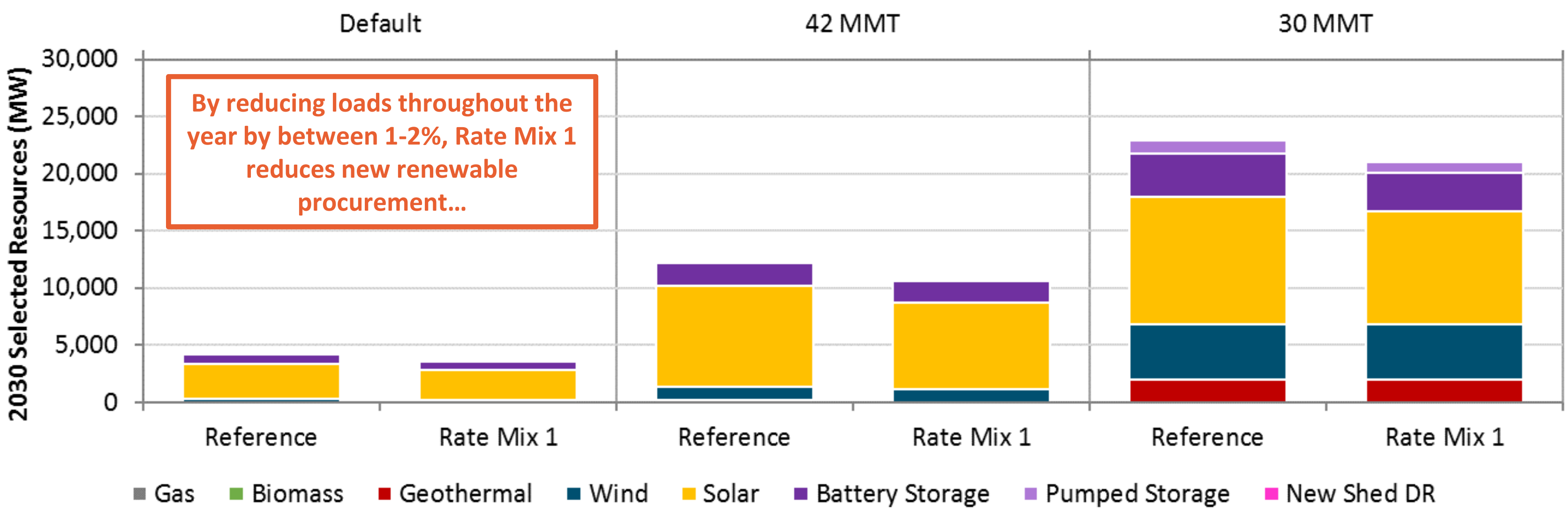


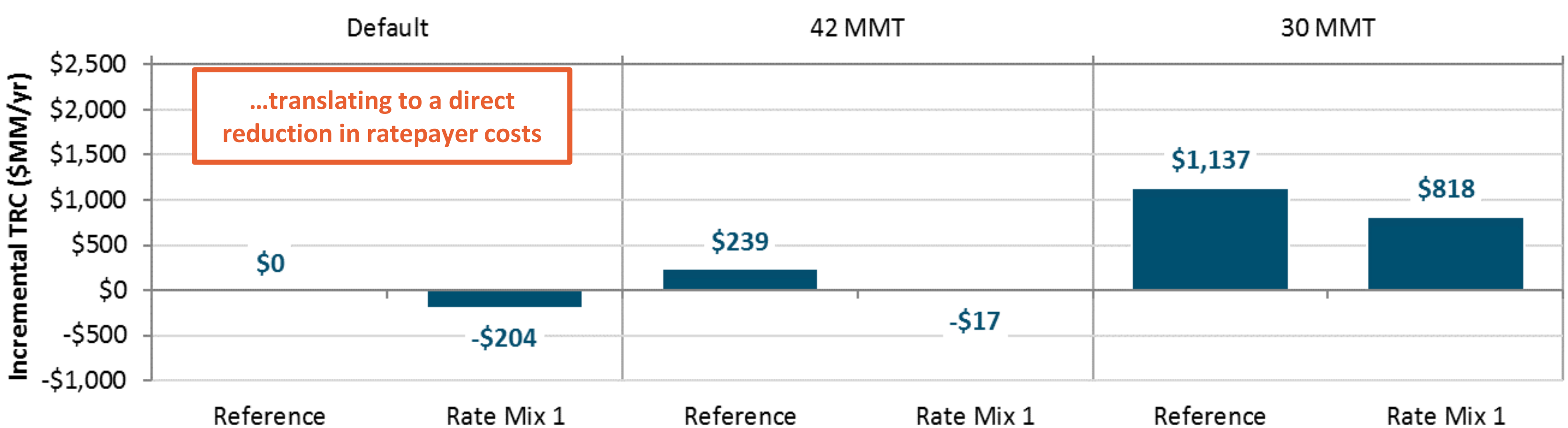
TOU Sensitivities: Summary Results from RESOLVE



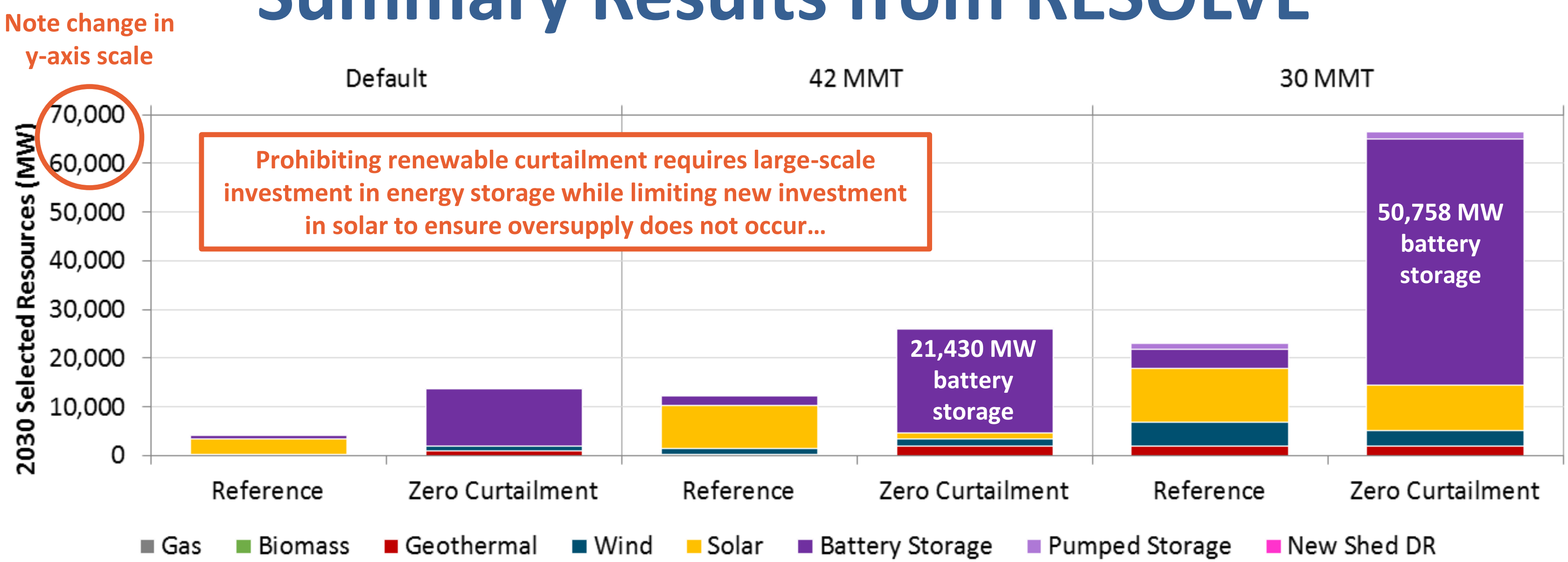


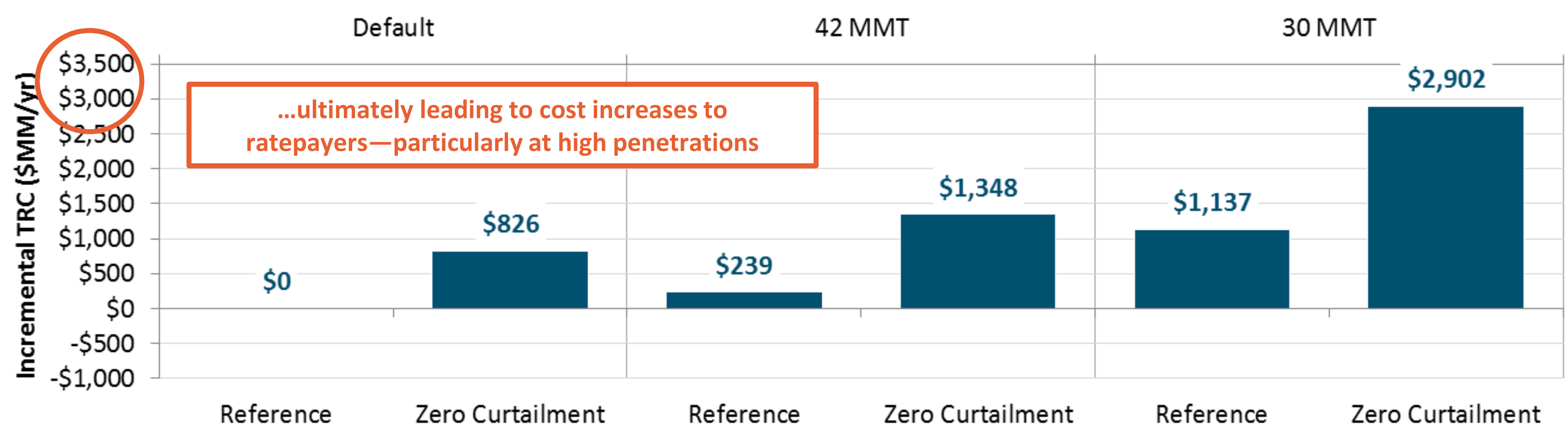
Rate Mix 1 Sensitivity: Summary Results from RESOLVE



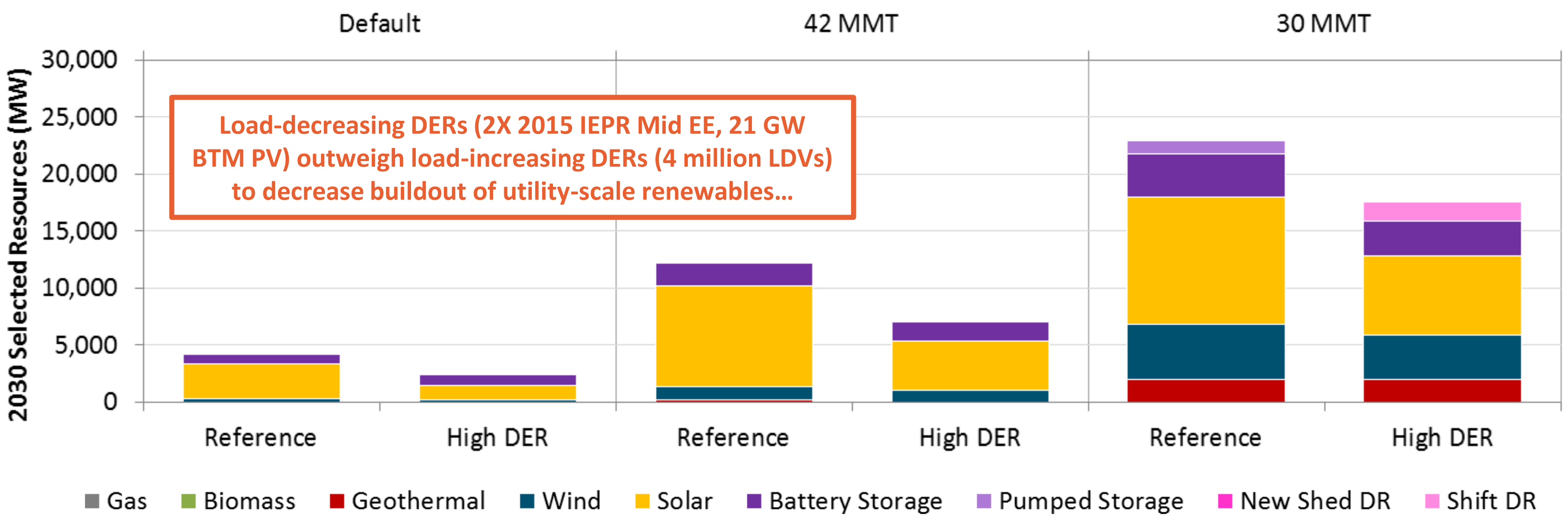


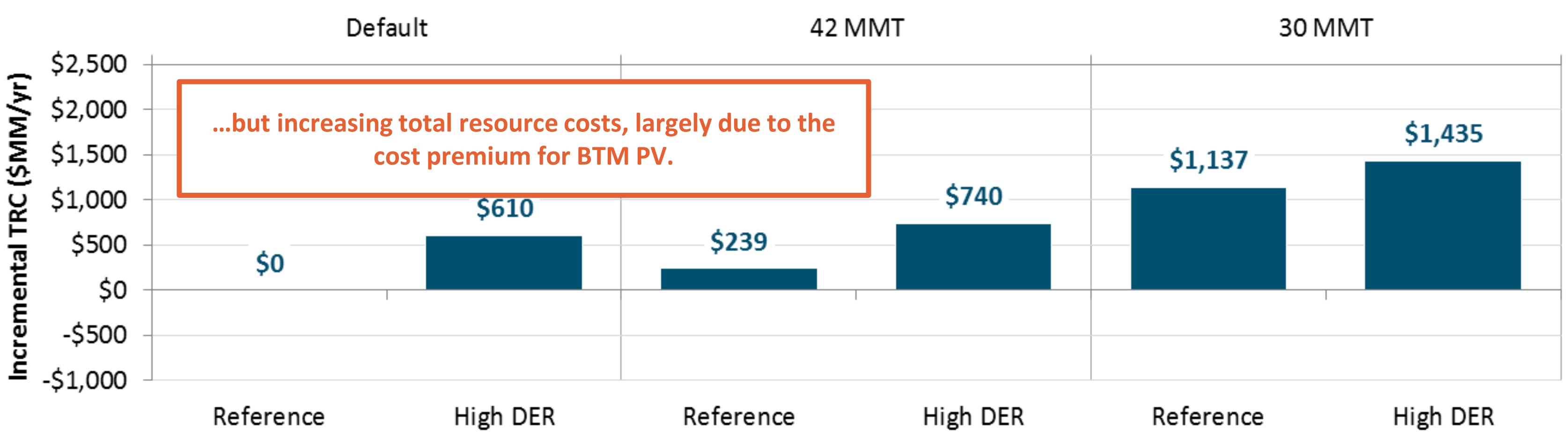
Zero Curtailment Sensitivity: Summary Results from RESOLVE





High DER:
Summary Results from RESOLVE





RESOLVE Output: Impact of Sensitivities on Incremental Cost (1/2)

All costs shown relative to Default Reference case

Sensitivity	Incremental TRC ($MM/yr)			Change from Reference ($MM/yr)		
	Default	42 MMT	30 MMT	Default	42 MMT	30 MMT
Reference	**$0**	**$239**	**$1,137**			
High EE	$120	$271	$1,048	**+$120**	**+$33**	**-$89**
Low EE	-$87	$282	$1,331	**-$87**	**+$43**	**+$193**
High BTM PV	$471	$677	$1,577	**+$471**	**+$438**	**+$440**
Low BTM PV	-$734	-$444	$480	**-$734**	**-$682**	**-$657**
Flexible EVs	-$66	$132	$935	**-$66**	**-$107**	**-$202**
High PV Cost	$240	$510	$1,419	**+$240**	**+$271**	**+$282**
Low PV Cost	-$280	-$137	$730	**-$280**	**-$376**	**-$407**
High Battery Cost	$264	$532	$1,470	**+$264**	**+$294**	**+$333**
Low Battery Cost	-$218	-$9	$617	**-$218**	**-$248**	**-$521**
No Tax Credits	$69	$382	$1,391	**+$69**	**+$143**	**+$253**
Gas Retirements	$351	$480	$1,233	**+$351**	**+$241**	**+$96**

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

RESOLVE Output: Impact of Sensitivities on Incremental Cost (2/2)

All costs shown relative to Default Reference case

Sensitivity	Incremental Cost ($MM/yr)			Change from Reference ($MM/yr)		
	Default	42 MMT	30 MMT	Default	42 MMT	30 MMT
Reference	**$0**	**$239**	**$1,137**			
CHP Retirement	-$82	$75	$762	-$82	-$163	-$376
Flex Challenged	$68	$398	$1,459	+$68	+$159	+$322
High Load	-$388	$322	$1,697	-$388	+$84	+$560
High Local Need	$33	$270	$1,161	+$33	+$31	+$24
Low DR	-$35	$204	$1,103	-$35	-$35	-$35
Low TOU	$7	$246	$1,144	+$7	+$8	+$7
Mid TOU	$4	$242	$1,141	+$4	+$4	+$3
Rate Mix 1	-$204	-$17	$818	-$204	-$255	-$319
Zero Curtailment	$826	$1,348	$2,902	+$826	+$1,109	+$1,764
High DER	$610	$740	$1,435	+$610	+$502	+$297

"Incremental TRC" calculated relative to "Default Reference" case (highlighted in orange

"Change from Reference" calculated relative to corresponding "Reference" case

Sensitivity Analysis: Observations

Sensitivities	Observations
Energy Efficiency	Value of incremental energy efficiency increases significantly under increasingly stringent carbon constraints; under less stringent carbon constraints, the value of the additional EE is less than the cost based on the assumed program costs.
Behind-the-Meter PV	Increases in BTM PV result in increased costs (including customer costs) in all scenarios; reductions in BTM PV result in reduced costs.
Flexible EVs	Allowing flexible EV charging reduces renewable curtailment, providing grid integration benefits; those benefits increase with higher renewable penetrations or under increased GHG targets.
PV Cost	Larger-than-expected reductions in PV cost reduce overall portfolio costs; smaller reductions result in higher cost portfolios and shift portfolios away from solar PV resources.
Battery Cost	Reductions in battery cost lower overall portfolio costs. The impact is modest in comparison to other sensitivities.
Tax Credits	If procurement is deferred until after tax credits expire, 2030 costs to ratepayers may increase significantly; in other words, accelerated procurement of renewables (in spite of current surplus) could result in significant savings if tax credits are not extended.
Gas Retirements	Accelerated retirement of gas resources drives significant increase in the total cost metric, mainly a result of the need to invest in new resources that can replace system resource adequacy provided by the retired gas capacity.

Additional Sensitivity Analysis: Observations

Sensitivities	Observations
CHP Retirements	Retirement of baseload CHP—an inflexible resource—increases operational flexibility and reduces the challenge of renewable integration. This impact results in reduced costs, as fewer investments in renewables and storage are added to meet policy goals.
Flexibility Challenged	Constraints that limit operational flexibility of the system (minimum generation, low net exports) exacerbate renewable curtailment, increasing the cost of meeting policy goals and requiring additional investment.
High Load	Sensitivity combines low BTM PV, low EE, high EVs, and high building electrification; multiple moving pieces make it difficult to isolate specific impacts in this sensitivity.
High Local Need	Hypothetical local need is met primarily by DR resources, which result in a modest increase in cost.
Low DR	The elimination of existing economically dispatched DR programs from the set of baseline resources results in a reduction in cost, as these programs have little value in today's system due to the existing capacity surplus. This finding changes if significant quantities of gas retire earlier than expected.
TOU Rates	Reductions in the load impact associated with default residential TOU rates (Low TOU/Mid TOU) cause a very slight increase in total costs. Rate Mix 1, which predicts a larger reduction in loads due to TOU pricing, leads to cost savings due to the assumed reduction in annual load (1-2%).
Zero Curtailment	Preventing curtailment shifts all portfolios towards energy storage and away from solar, as all oversupply must be stored rather than curtailed; this portfolio criterion results in a significant increase in costs

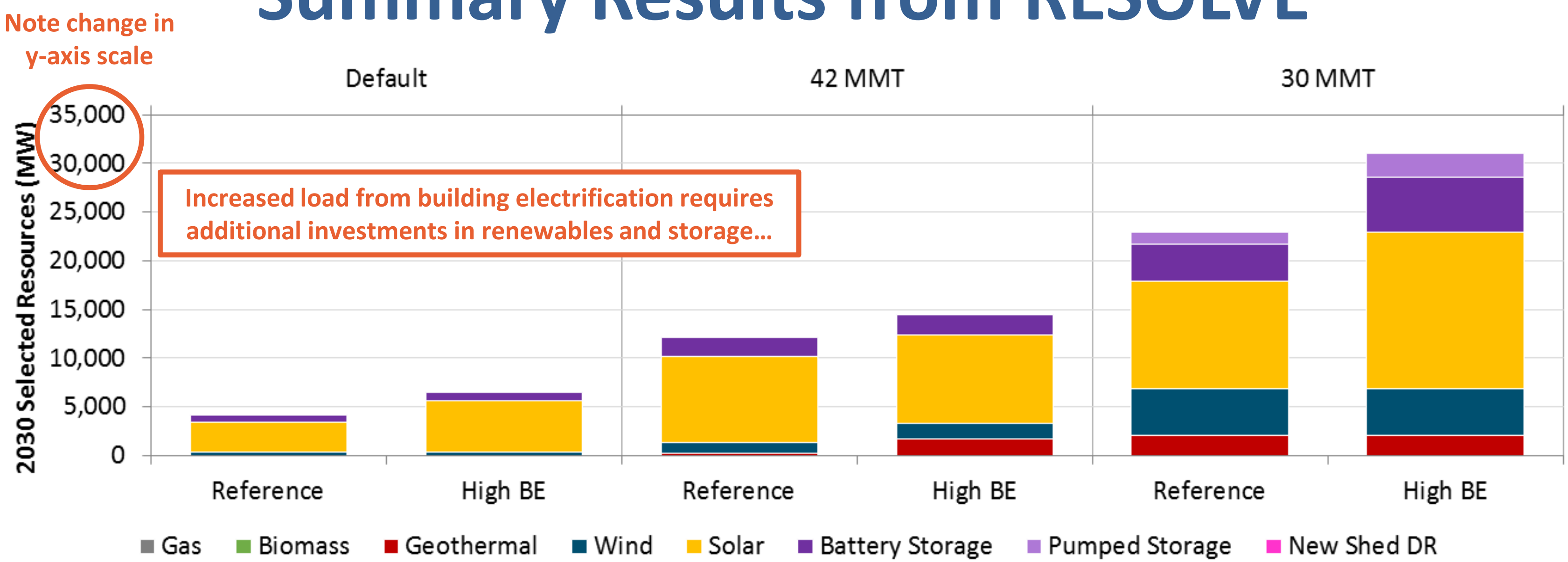
Summary of Observations on Core Policy Case Sensitivities

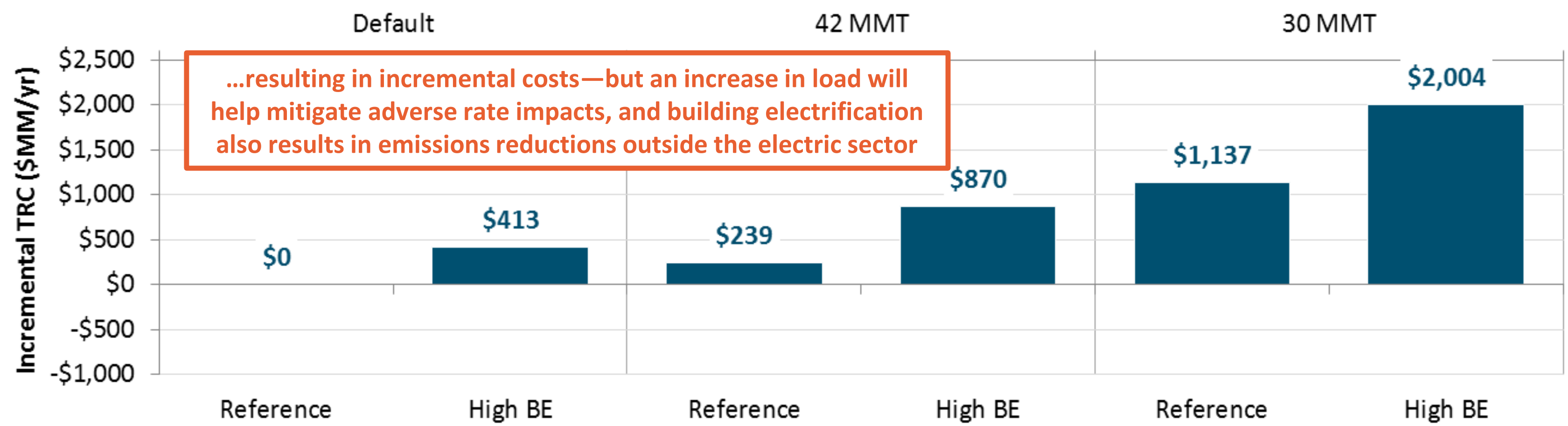
- With some exceptions, the least-cost portfolio composition for meeting different GHG targets and reliability constraints does not change much under different assumptions about the future
- Generally, model results indicate that utility-scale solar PV and wind procured within next 1-3 years to take advantage of federal tax credits are part of least-cost solution for 2030
- Modeled future conditions that tend to increase total resource costs: high levels of BTM PV, zero curtailment (requires 20,000 MW of additional battery storage in 42 MMT case), no tax credits, gas retirement, high loads, high technology costs

Interpreting Results of Cross-Sectoral Sensitivities

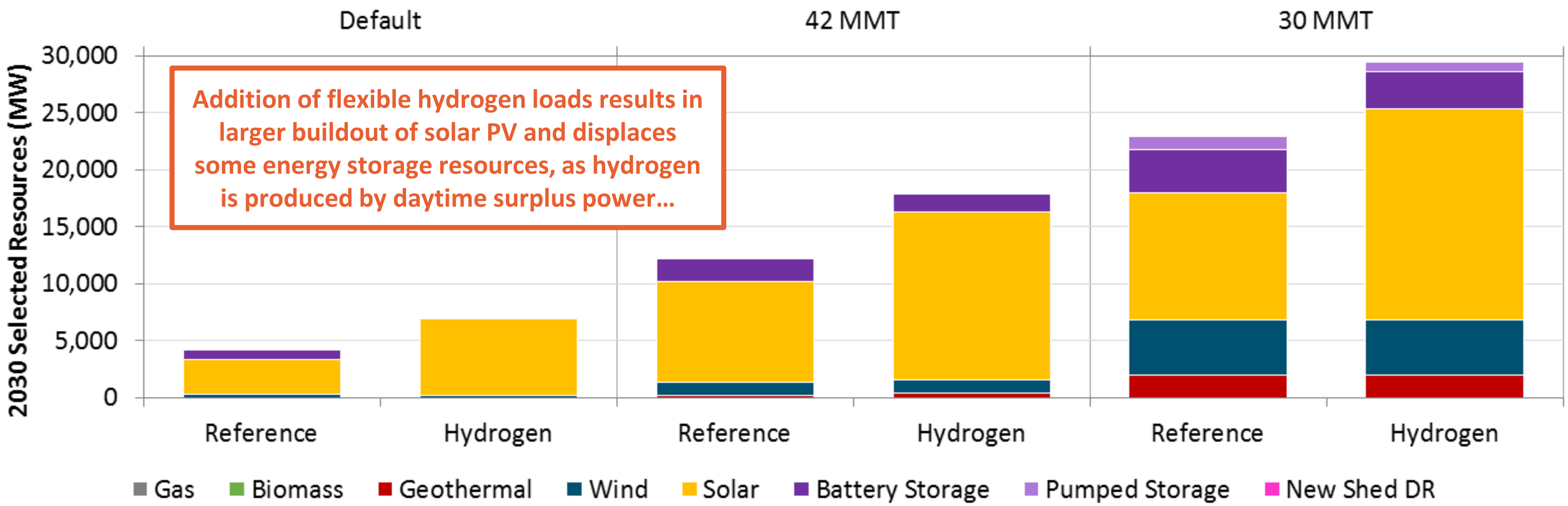
- Two of the sensitivities designed in this study examine how measures undertaken in other sectors of the economy to meet GHG goals could impact the electric sector:
  - High Building Electrification
  - Hydrogen Loads
- The results of these sensitivities provide a useful measure of how the electric sector might respond to such changes, but do not provide a complete picture of the impacts of such changes
  - Analysis does not evaluate costs and/or benefits outside the electric sector (e.g. avoided gasoline or natural gas purchases)
  - Analysis does not consider greenhouse gas benefits associated with electrification of end uses
- Accordingly, these sensitivities should be interpreted as “what-if?” analyses of potential cross-sectoral impacts, but cannot be used alone as justification for policy decisions on these types of measures

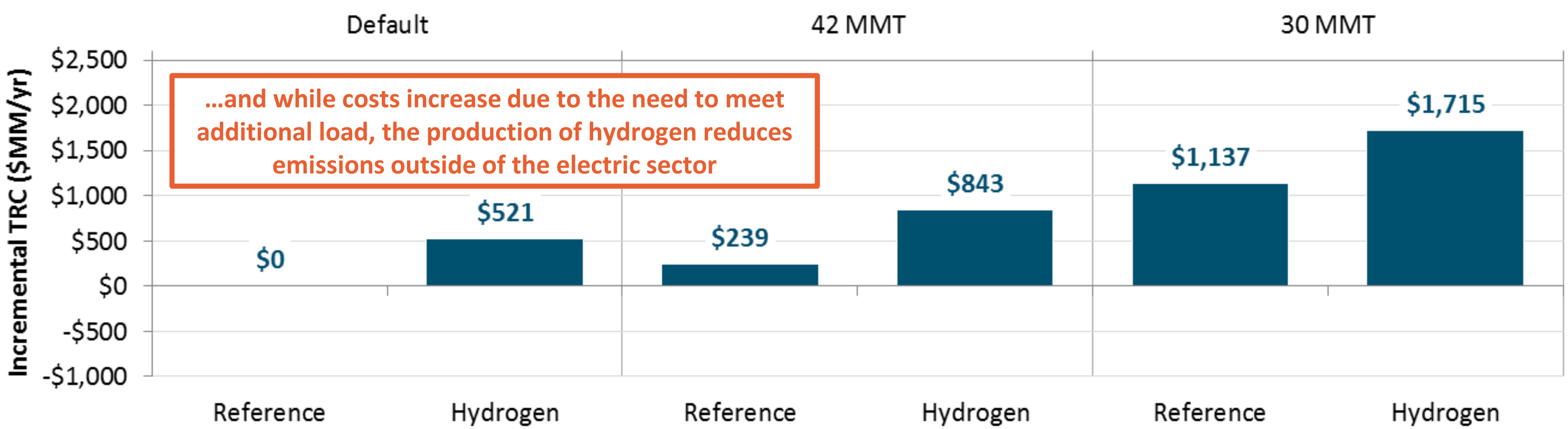
High Building Electrification Sensitivity: Summary Results from RESOLVE





Hydrogen Sensitivity: Summary Results from RESOLVE





APPENDIX C
DETAILED RESOURCE STUDIES

Resource Studies

- This appendix provides additional detail on how the Resource Studies reported in the Reference System Plan were conducted
- While some slides that appeared in the body of the Reference System Plan are repeated here, this appendix also provides additional information on the questions that framed the analysis and how it was structured.

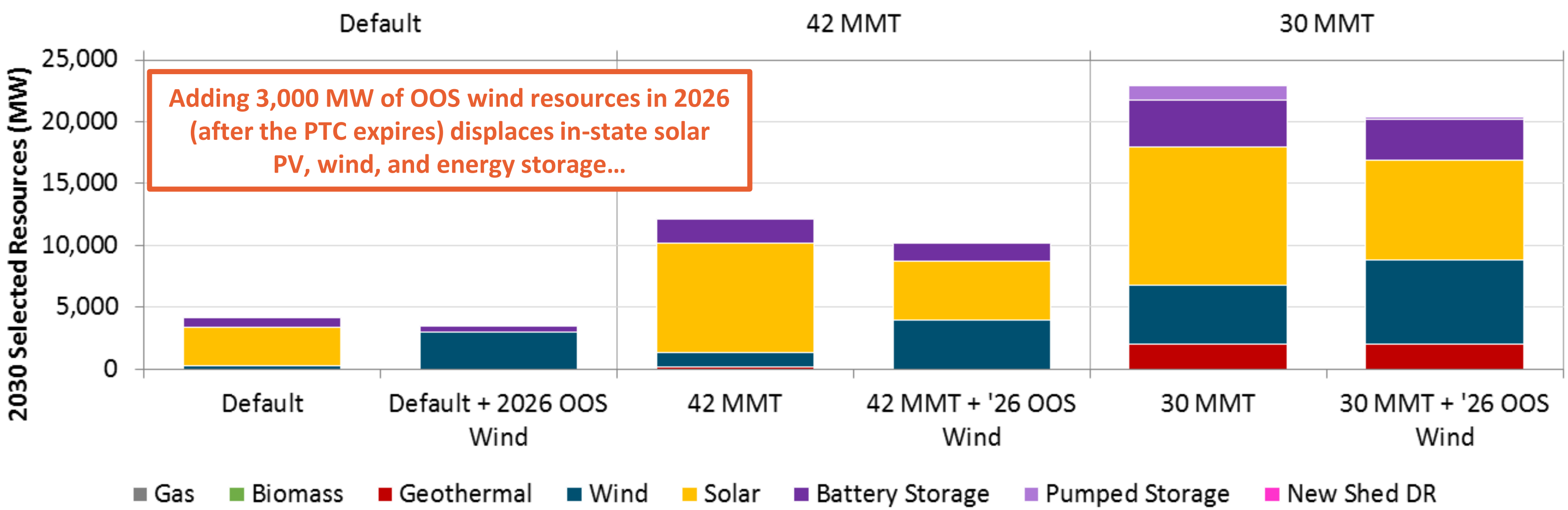
Resources Selected for Detailed Study

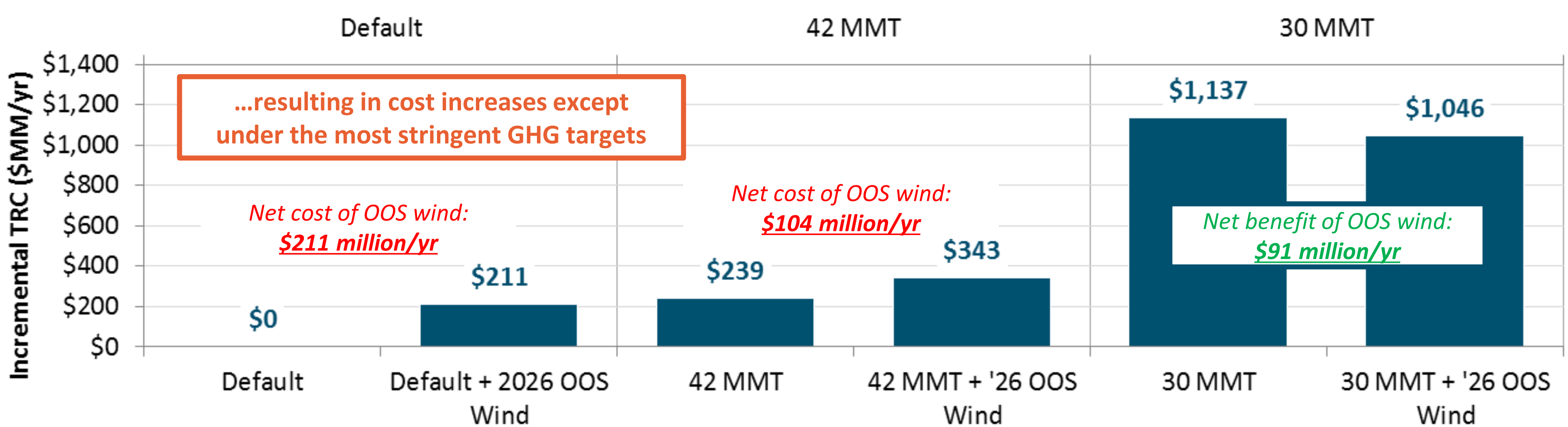
- Staff selected certain resources to study in greater detail:
  - Pumped storage
  - Geothermal
  - OOS wind
- Pumped storage and geothermal resources were available for selection and chosen by the model in some cases (e.g., see 30 MMT case), but typically not until 2030
- OOS wind on new transmission was not available for selection in the core cases and sensitivities due to uncertainty in the cost and feasibility of the required transmission
- These detailed studies are designed to provide information to decision makers about the value and risk of procuring these resources **in the near term**
- In each case, the resource is manually added to the portfolio in the **earliest possible year** that it could be available based on estimated lead times for each resource type

OOS Wind Study: Overview

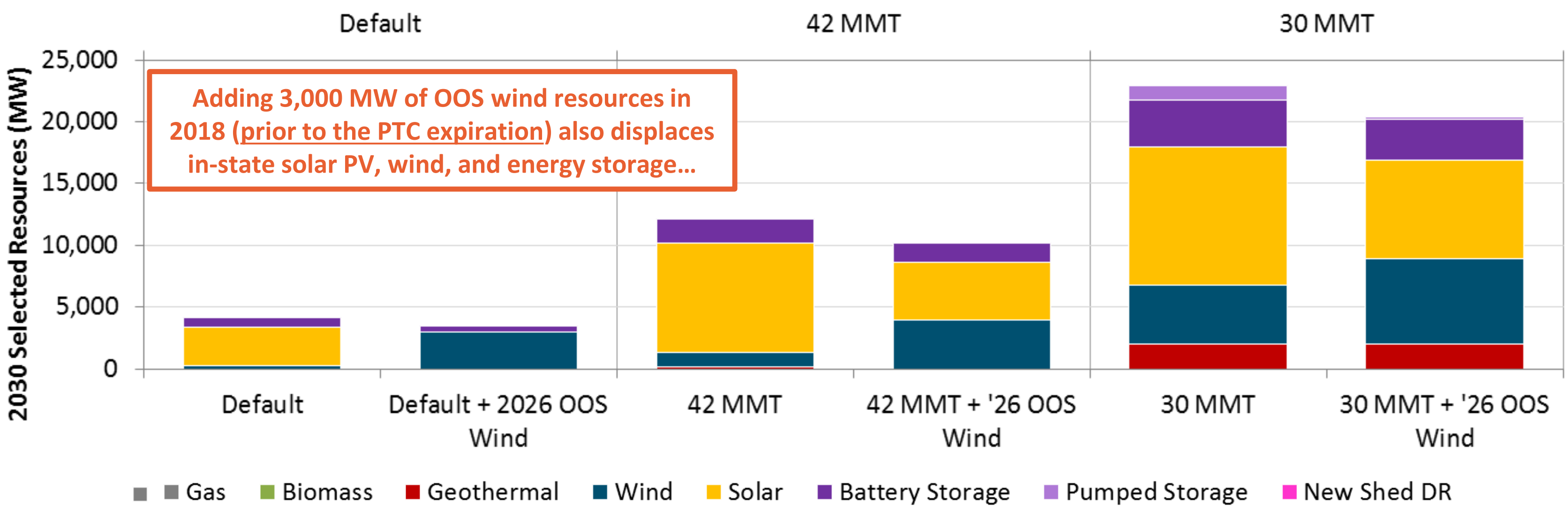
- **Study Question:**
  - Does procuring OOS wind **in the near-term** reduce risk and/or cost across a broad range of sensitivities?
- **Study Design**
  - Manually add 3,000 MW of WY & NM wind (along with associated transmission to CA) to the portfolio in 2026 to assess its impact
  - Test with three core cases (Default, 42 MMT, 30 MMT) and all main sensitivities
- **Key Assumptions**
  - Assume development of two new 500kV transmission lines to deliver wind to California

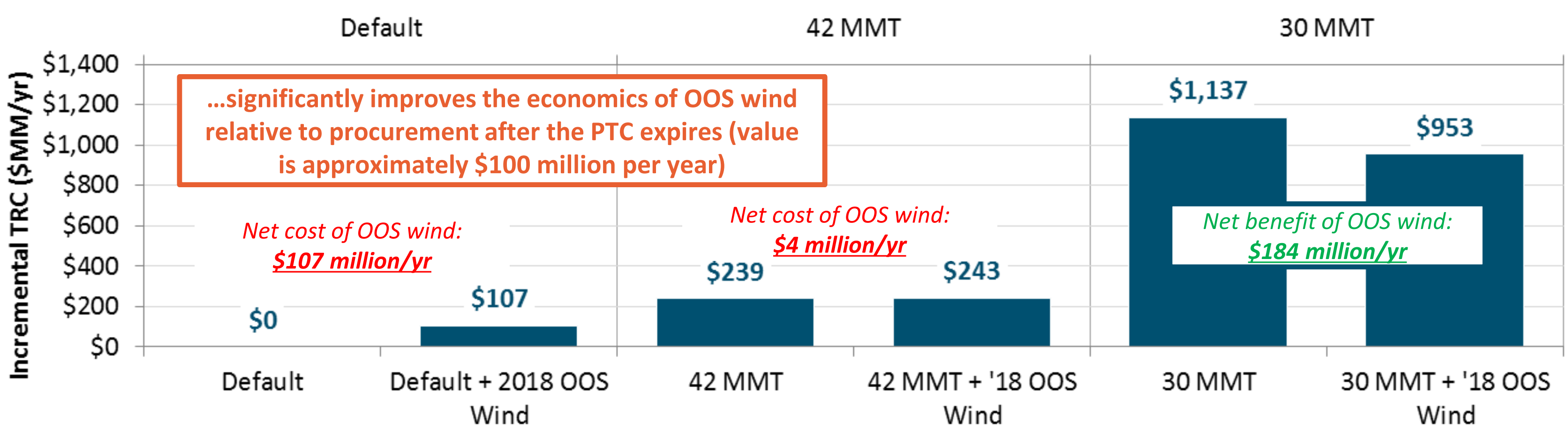
OOS Wind Built in 2026: Portfolio Summary





OOS Wind Built in 2018: Portfolio Summary





OOS Wind Built in 2026:
Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ 2026 OOS Wind	Change	Base Case	+ 2026 OOS Wind	Change	Base Case	+ 2026 OOS Wind	Change
Reference	**$0**	**$211**	**+$211**	**$239**	**$343**	**+$104**	**$1,137**	**$1,046**	**-$91**
High EE	$120	$341	**+$220**	$271	$410	**+$139**	$1,048	$994	**-$54**
Low EE	-$87	$107	**+$194**	$282	$334	**+$52**	$1,331	$1,211	**-$120**
High BTM PV	$471	$687	**+$217**	$677	$786	**+$109**	$1,577	$1,497	**-$80**
Low BTM PV	-$734	-$522	**+$212**	-$444	-$356	**+$88**	$480	$380	**-$100**
Flexible EVs	-$66	$155	**+$221**	$132	$262	**+$130**	$935	$863	**-$72**
High PV Cost	$240	$437	**+$198**	$510	$593	**+$84**	$1,419	$1,314	**-$105**
Low PV Cost	-$280	-$42	**+$239**	-$137	$20	**+$157**	$730	$687	**-$43**
High Battery Cost	$264	$473	**+$209**	$532	$619	**+$87**	$1,470	$1,373	**-$98**
Low Battery Cost	-$218	$3	**+$221**	-$9	$116	**+$125**	$617	$659	**+$42**
No Tax Credits	$69	$211	**+$142**	$382	$415	**+$34**	$1,391	$1,226	**-$165**
Gas Retirements	$351	$481	**+$130**	$480	$530	**+$50**	$1,233	$1,121	**-$112**

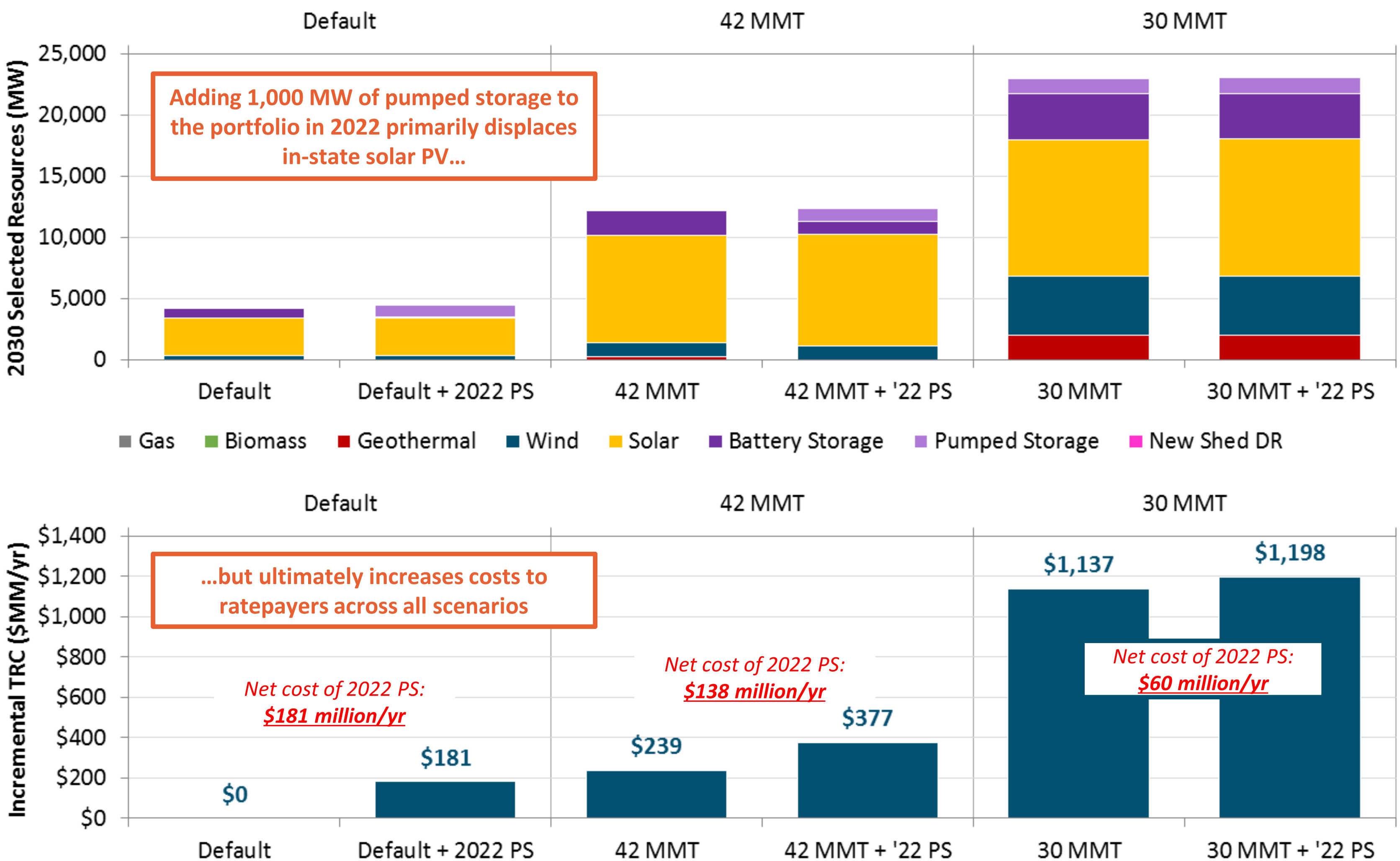
Observations on Near-Term OOS Wind

- The relative economic attractiveness of OOS wind resources increases under increasingly stringent GHG targets
  - In the 30 MMT Case a large, near-term OOS wind project will provide significant benefits to ratepayers across a broad range of sensitivities
- The ability to procure OOS wind resources prior to the expiration of the PTC significantly improves the economics under all GHG targets
  - 3,000 MW wind procured in 2018 (with the PTC) is approximately $100 MM/yr cheaper than the same resource procured in 2026 (without the PTC) *on a levelized basis*
  - The timing of procurement, and a project's ability to capture the PTC, could be a major factor in the competitiveness of OOS wind projects
- **Caveat**: Because this analysis assumes OOS wind requires major new multi-state transmission investment to deliver directly to California, it may understate the potential benefits to ratepayers
  - Additional follow-up analysis based on RETI 2.0 transmission analysis could identify potential lower cost transmission solutions

Pumped Storage Study: Overview

- **Study Questions**
  - Does procuring pumped storage **in the near-term** reduce risk and/or cost across a broad range of sensitivities?
- **Study Design**
  - Examine the impact of manually adding **1,000 MW of pumped storage** into the portfolio **in 2022** to assess the cost impact of procuring pumped storage in the near term ("Near-Term Pumped Storage Portfolios")
  - Examine the quantity of pumped storage that appears in the 2030 optimal portfolio across all main sensitivities under each core case (Default, 42 MMT, 30 MMT)

Pumped Storage Built in 2022: Portfolio Summary



Pumped Storage Built in 2022: Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($B)		
	Base Case	+ 2022 PS	Change	Base Case	+ 2022 PS	Change	Base Case	+ 2022 PS	Change
Reference	$0	$181	**+$181**	$239	$377	**+$138**	$1,137	$1,198	**+$60**
High EE	$120	$303	**+$183**	$271	$432	**+$161**	$1,048	$1,115	**+$67**
Low EE	-$87	$91	**+$179**	$282	$407	**+$125**	$1,331	$1,391	**+$60**
High BTM PV	$471	$648	**+$177**	$677	$816	**+$140**	$1,577	$1,641	**+$64**
Low BTM PV	-$734	-$547	**+$187**	-$444	-$307	**+$137**	$480	$541	**+$61**
Flexible EVs	-$66	$119	**+$185**	$132	$286	**+$155**	$935	$997	**+$62**
High PV Cost	$240	$422	**+$182**	$510	$649	**+$140**	$1,419	$1,481	**+$62**
Low PV Cost	-$280	-$100	**+$180**	-$137	$4	**+$141**	$730	$791	**+$61**
High Battery Cost	$264	$441	**+$177**	$532	$647	**+$115**	$1,470	$1,529	**+$59**
Low Battery Cost	-$218	-$22	**+$195**	-$9	$155	**+$164**	$617	$754	**+$137**
No Tax Credits	$69	$254	**+$185**	$382	$536	**+$154**	$1,391	$1,467	**+$76**
Gas Retirements	$351	$472	**+$122**	$480	$585	**+$105**	$1,233	$1,294	**+$60**

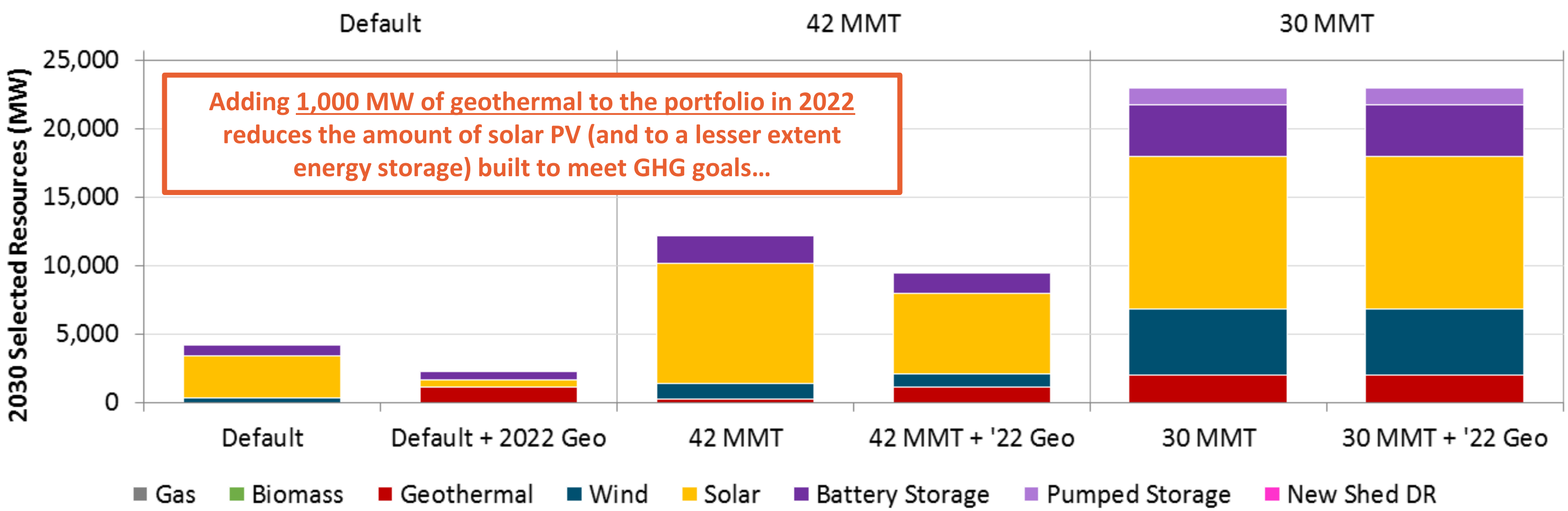
Observations Regarding Pumped Storage

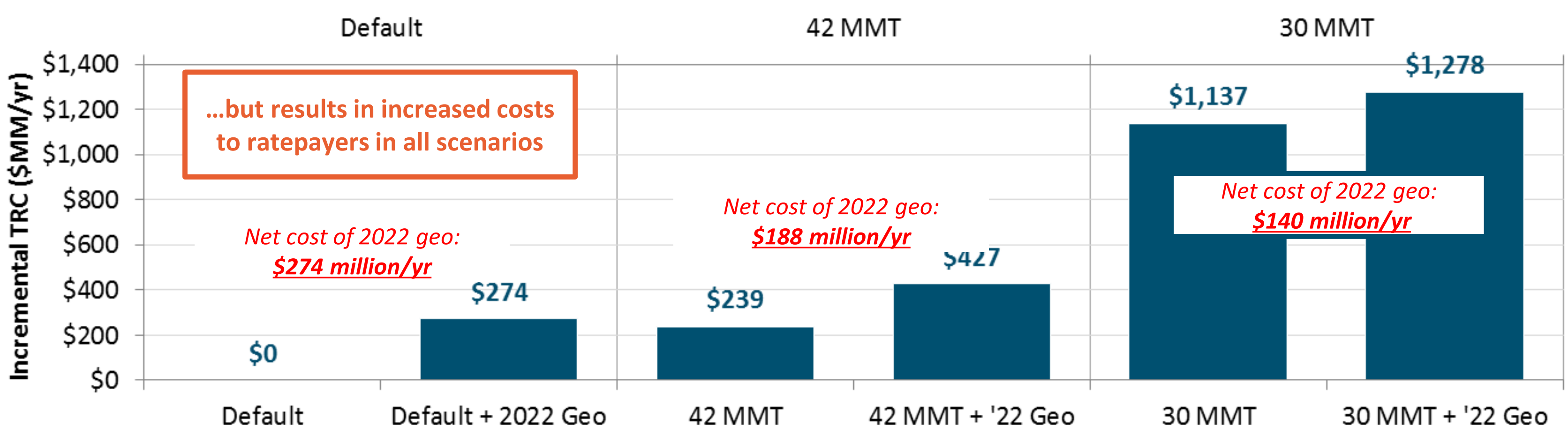
- **Relative benefit of pumped storage in 2030 is directly tied to selection of GHG target**
  - Pumped storage not selected in optimal portfolio or most sensitivities under the Default and 42 MMT Cases
  - Adding pumped storage may become cost-effective between the 42 MMT and 30 MMT Cases
  - All sensitivities in the 30 MMT Case include some pumped storage
- **Addition of pumped storage in the near-term results in some cost increases across all scenarios**
  - Under Default Case, pumped storage results in cost increases across all sensitivities
  - In 30 MMT Case, adding pumped storage in 2022 has a limited impact on long term system costs
    - Since pumped storage is part of the optimal 2030 portfolio, the cost premium in these cases reflects the cost of early action

Geothermal Energy Study: Overview

- **Study Questions**
  - Does procuring geothermal resources **in the near-term** reduce risk and/or cost across a broad range of sensitivities?
- **Study Design**
  - Examine the impact of manually adding **1,000 MW of geothermal** into the portfolio **in 2022** to assess the cost impact of procuring geothermal resources in the near term
  - Examine the quantity of geothermal resources that appear in the 2030 optimal portfolio across a broad range of sensitivities

Geothermal Built in 2022: Portfolio Summary





Geothermal Built in 2022: Sensitivity Analysis on Incremental TRC

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ 2022 Geo	Change	Base Case	+ 2022 Geo	Change	Base Case	+ 2022 Geo	Change
Reference	$0	$274	**+$274**	$239	$427	**+$188**	$1,137	$1,278	**+$140**
High EE	$120	$403	**+$283**	$271	$495	**+$224**	$1,048	$1,194	**+$146**
Low EE	-$87	$177	**+$264**	$282	$434	**+$152**	$1,331	$1,462	**+$131**
High BTM PV	$471	$748	**+$278**	$677	$870	**+$194**	$1,577	$1,718	**+$140**
Low BTM PV	-$734	-$457	**+$277**	-$444	-$261	**+$183**	$480	$614	**+$134**
Flexible EVs	-$66	$219	**+$285**	$132	$346	**+$214**	$935	$1,076	**+$141**
High PV Cost	$240	$502	**+$263**	$510	$684	**+$174**	$1,419	$1,562	**+$142**
Low PV Cost	-$280	$23	**+$303**	-$137	$94	**+$232**	$730	$871	**+$141**
High Battery Cost	$264	$537	**+$273**	$532	$706	**+$174**	$1,470	$1,609	**+$139**
Low Battery Cost	-$218	$66	**+$284**	-$9	$202	**+$211**	$617	$759	**+$143**
No Tax Credits	$69	$278	**+$210**	$382	$510	**+$128**	$1,391	$1,469	**+$78**
Gas Retirements	$351	$562	**+$211**	$480	$634	**+$155**	$1,233	$1,373	**+$140**

Observations Regarding Geothermal Energy

- **Relative benefits of geothermal in 2030 is directly tied to selection of GHG target**
  - Default Case: Geothermal not included in any optimal portfolios
  - 42 MMT Case: In some sensitivities, geothermal is selected
  - 30 MMT Case: Maximum in-state geothermal potential is selected in all sensitivities by 2030
- **Near-term procurement of geothermal increases cost across all scenarios**
  - In Default and 42 MMT Cases, geothermal displaces less costly resources from portfolios
  - In 30 MMT Case, cost increase is mainly driven by having to procure a costly resource before it is needed

Summary of Observations from Resource Studies

- Under the 42 MMT procurement target, near-term procurement of OOS Wind represents a relatively low-cost investment that mitigates financial risk associated with high PV costs, high storage costs, or low EE achievement
  - More work needed to determine what resource areas, transmission lines, or other activities may be possible or necessary to maximize value of OOS wind
- Near-term procurement of pumped storage and geothermal energy tends to increase costs across a broad range of future conditions
  - Staff recommends requiring additional scrutiny of non-geothermal PPAs located in areas with geothermal resources in order to preserve option of transmission access for geothermal in future
  - Both pumped storage and geothermal energy should be studied in next IRP cycle to determine whether costs or values for near-term procurement of these resources have changed

APPENDIX D
OTHER STUDIES

Other studies

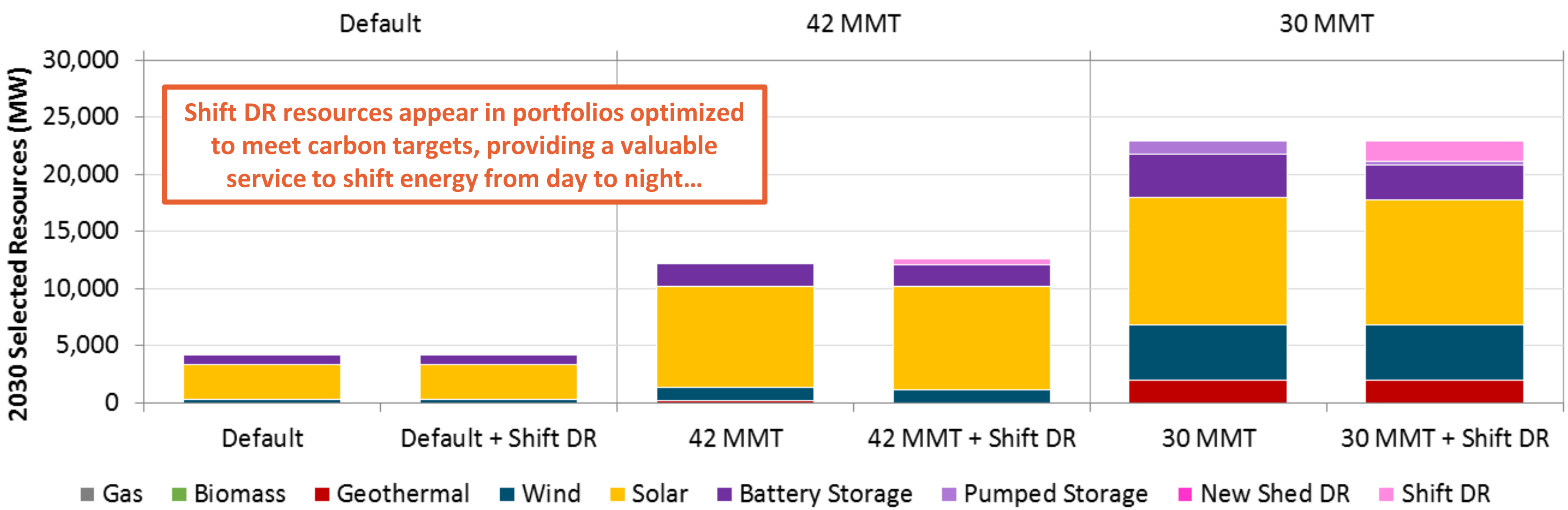
- In addition the analyses reported in the body of the Reference System Plan, Staff conducted additional studies on specific issues of interest
- This appendix provides additional detail on how these additional studies were conducted
- While some slides that appeared in the body of the Reference System Plan are repeated here, this appendix also provides additional information on the questions that framed the analysis and how it was structured.

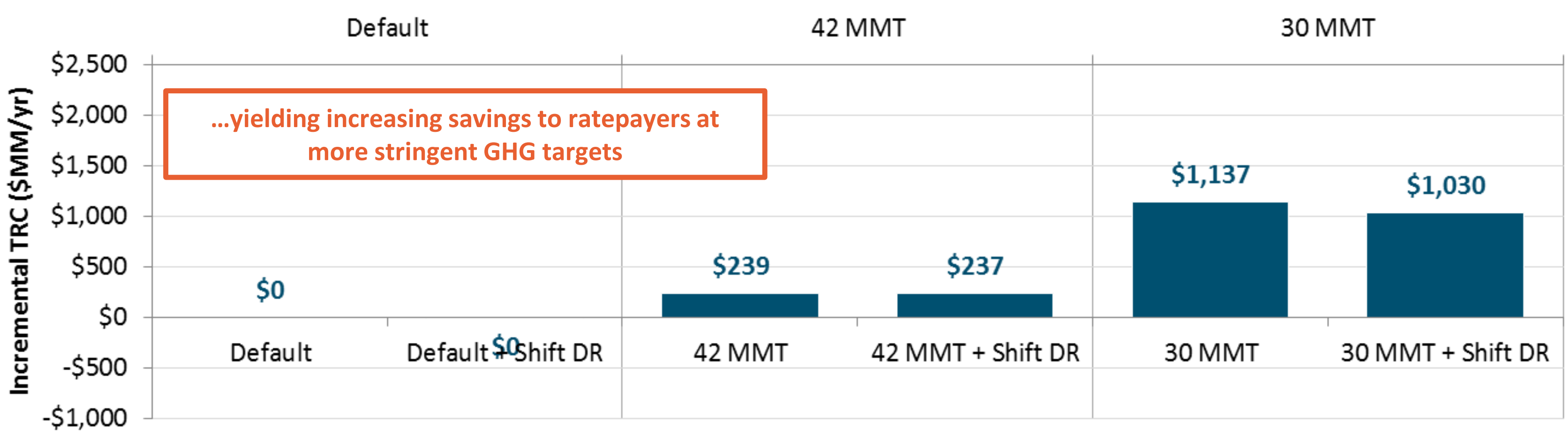
D.1. SHIFT DR

Shift DR Study: Overview

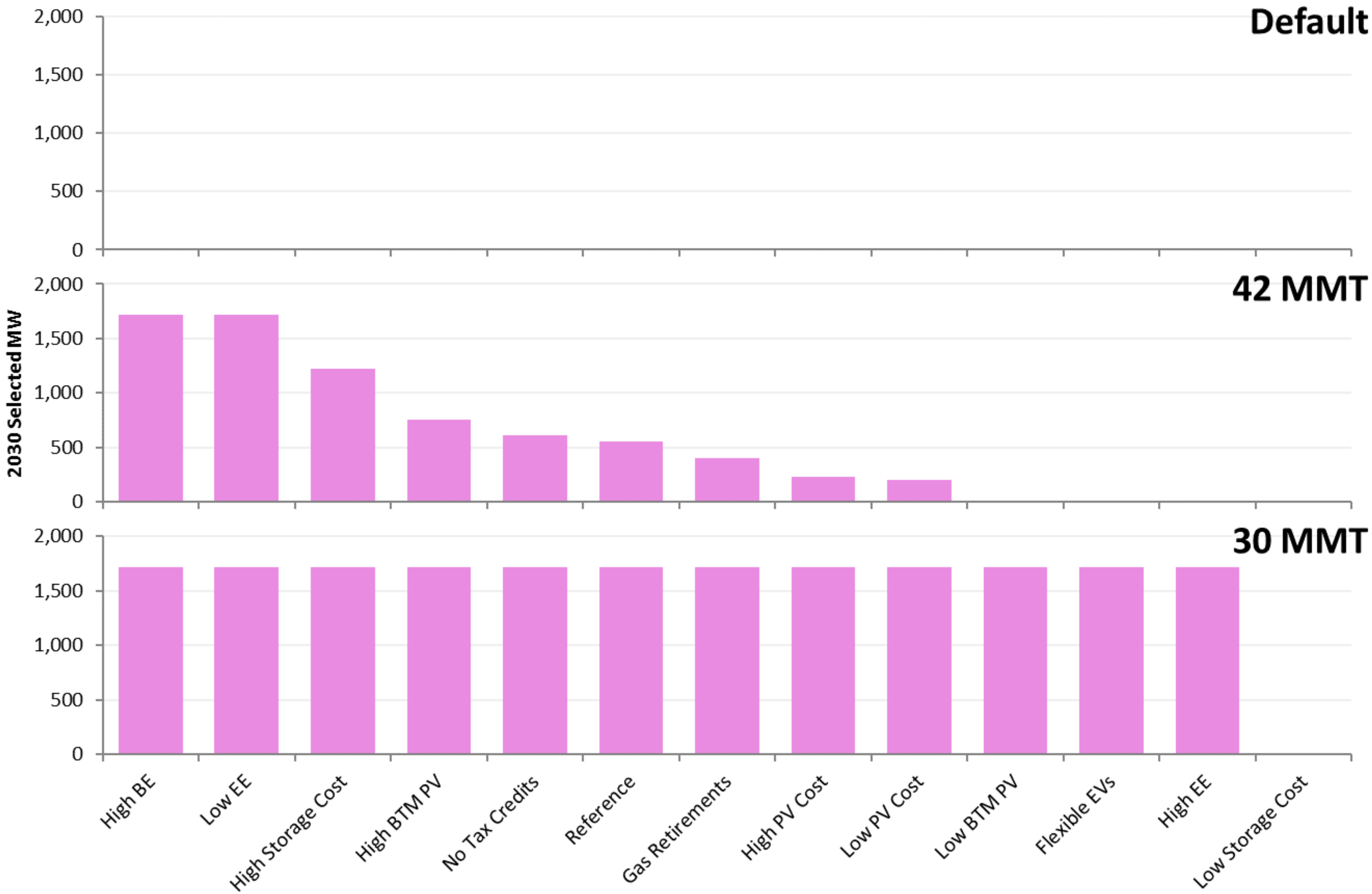
- **Study Questions**
  - Does making shift DR available for the model to select reduce risk and/or cost across a broad range of sensitivities?
  - Is there a minimum amount of shift DR that is selected across a road range of sensitivities?
- **Study Design**
  - Examine the impact of allowing RESOLVE to select shift DR in the core policy cases
  - Examine the quantity of shift DR that appears in the 2030 optimal portfolio across all main sensitivities under each core policy case (Default, 42 MMT, 30 MMT)

Shift DR Sensitivity: Summary Results





Shift DR Selected Across Sensitivities



Shift DR Portfolio:
Sensitivity Analysis on Incremental Cost

All costs shown relative to Default Reference case

Sensitivity	Default ($MM/yr) Base Case	Default ($MM/yr) + Shift DR	Default ($MM/yr) Change	42 MMT ($MM/yr) Base Case	42 MMT ($MM/yr) + Shift DR	42 MMT ($MM/yr) Change	30 MMT ($MM/yr) Base Case	30 MMT ($MM/yr) + Shift DR	30 MMT ($MM/yr) Change
Reference	$0	$0	—	$239	$237	-$2	$1,137	$1,030	-$108
High EE	$120	$120	—	$271	$271	—	$1,048	$950	-$98
Low EE	-$87	-$87	—	$282	$269	-$13	$1,331	$1,215	-$115
High BTM PV	$471	$471	—	$677	$675	-$2	$1,577	$1,471	-$106
Low BTM PV	-$734	-$734	—	-$444	-$444	—	$480	$374	-$107
Flexible EVs	-$66	-$66	—	$132	$132	—	$935	$835	-$100
High PV Cost	$413	$413	—	$870	$854	-$16	$2,004	$1,887	-$117
Low PV Cost	$240	$240	—	$510	$509	—	$1,419	$1,311	-$108
High Battery Cost	-$280	-$280	—	-$137	-$137	—	$730	$624	-$106
Low Battery Cost	[illegible]	[illegible]	—	$532	$527	-$5	$1,470	$1,354	-$116
No Tax Credits	[illegible]	[illegible]	—	-$9	-$9	—	$617	$617	—
Gas Retirements	[illegible]	[illegible]	—	$382	$381	-$1	$1,391	$1,283	-$108

Shift DR is selected in all cases that show savings

Observations on Shift DR Cases

- At less stringent GHG targets, renewable balancing challenges are not significant enough to justify payments to flexible loads
  - Limited renewable integration challenges
- At more stringent targets, balancing challenges become significant enough to incent addition of flexible loads to the system
  - More frequent renewable curtailment creates more value to incent shifting of loads

D.2. POST-2030 STUDY

Additional Analysis to Account for Uncertainty in Post 2030 Load

Goals

- Determine the impact of different plausible post-2030 load levels on the optimal portfolio in 2030

Factors Considered

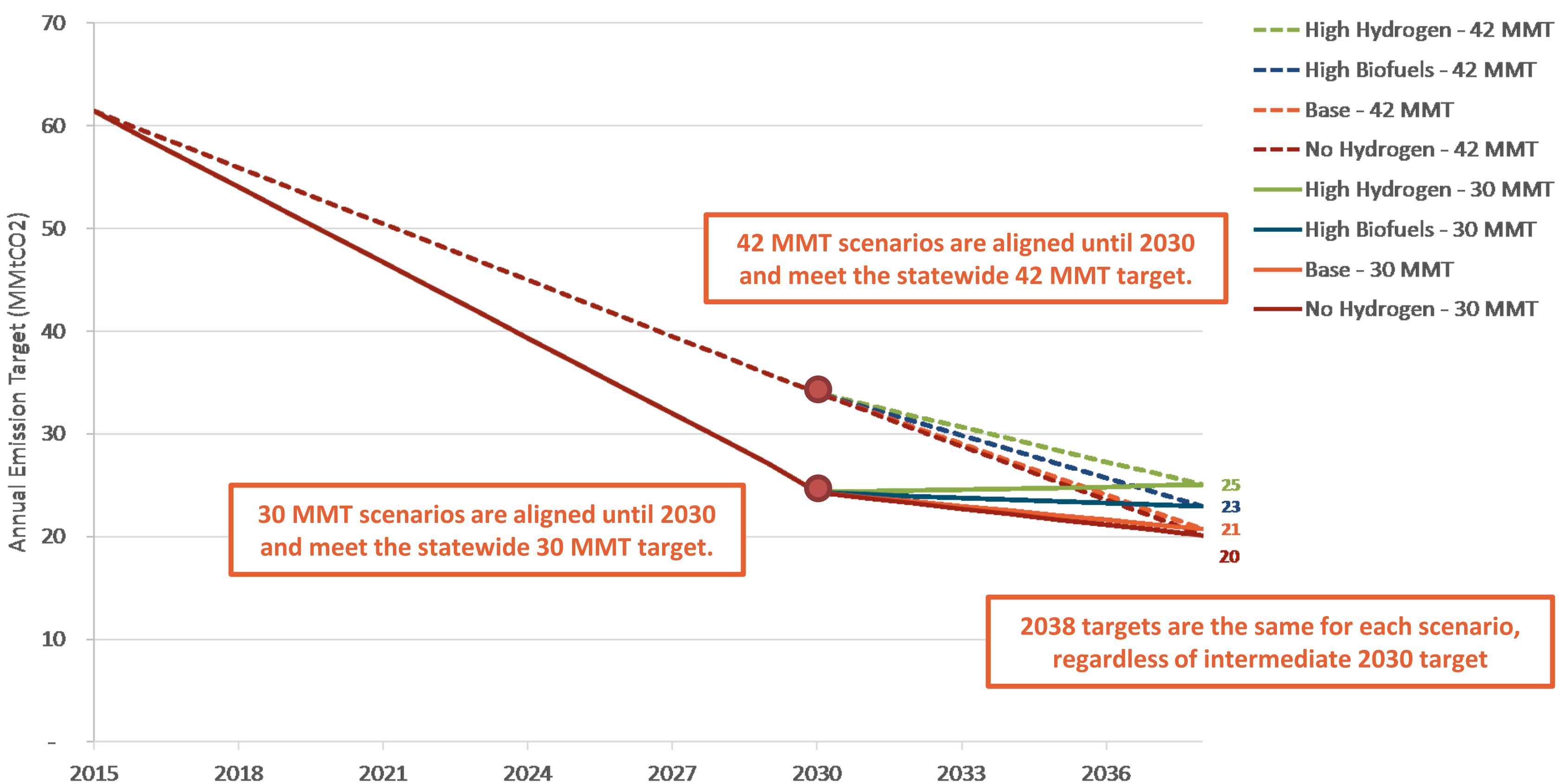
- IRP Planning Horizon is 20 Years: 2018-2038
- Focus of IRP in 2017-2018 is the state's GHG goal of 40% reduction below 1990 levels by 2030; however, long-term GHG goal is 80% reduction of 1990 levels by 2050
- Changes in other sectors (e.g. transportation electrification) may lead electricity demand to increases post 2030 due to fuel switching

Post-2030 Scenarios Evaluated

- Staff used the PATHWAYS model to run four different 2038 sensitivities
- All sensitivities are consistent with 80% reductions in economy-wide GHG emissions by 2050
- Scenarios were aligned with the two core GHG targets considered in the primary IRP analysis (30 MMT or 42 MMT) until 2030
  1. **Post 2030 Base**: PATHWAYS Base Mitigation case. Uses a mix of biofuels, hydrogen, EVs and other low carbon solutions. Fairly strict electric sector emission target (20.7 MMT in 2038).
  2. **Post 2030 High Biofuel**: PATHWAYS High Biofuel case. Focuses heavily on biofuels, resulting in less EV and hydrogen loads. Because biofuels avoid emissions in other sectors, the electric sector emission target is higher (22.9 MMT in 2038).
  3. **Post 2030 High Hydrogen**: PATHWAYS High Hydrogen case. Focuses heavily on hydrogen, resulting in very high hydrogen loads and lower EV loads. Because hydrogen avoids emissions in other sectors, the electric sector emission target is higher (25 MMtCO2 in 2038).
  4. **Post 2030 No Hydrogen**: PATHWAYS No Hydrogen case. Scenario without hydrogen, resulting in higher EV loads and a tighter electric sector emission target (20.1 MMT in 2038).

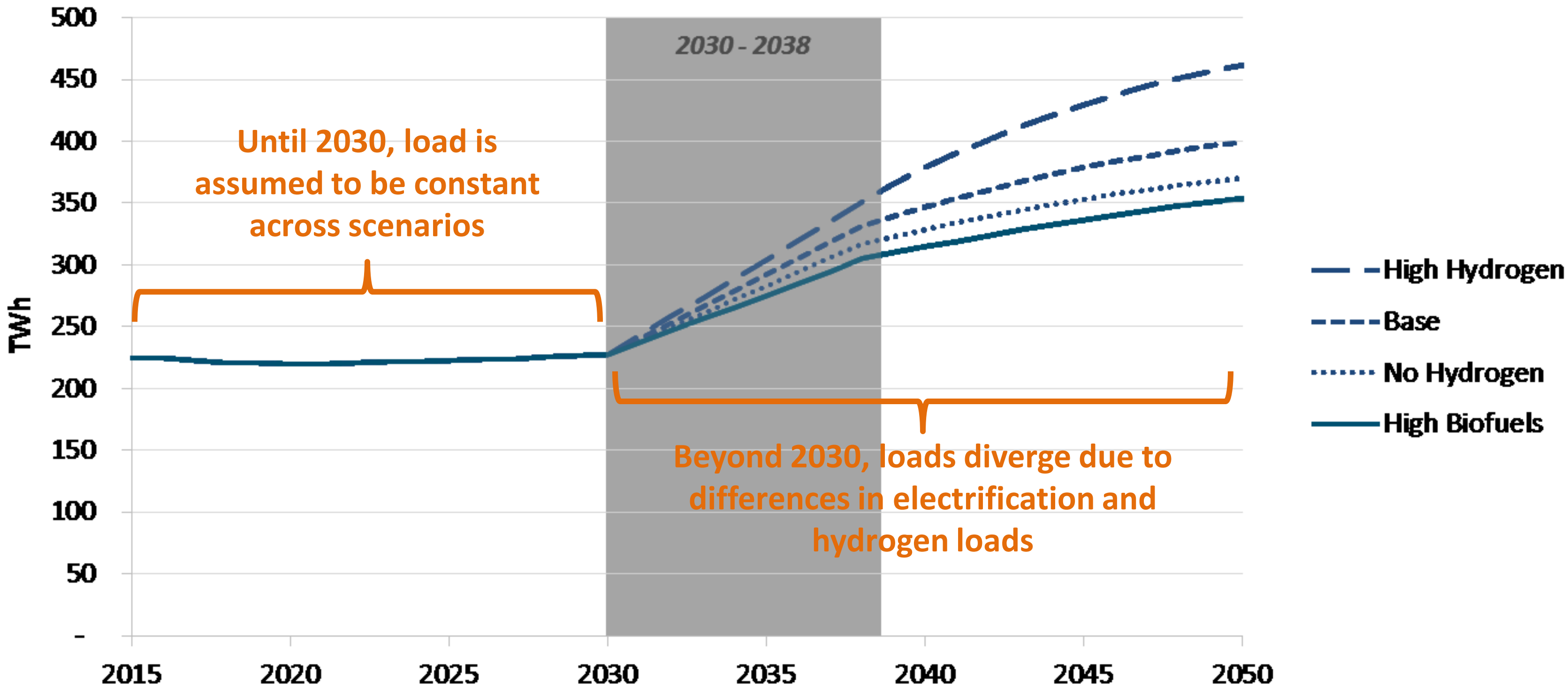
Potential Electric Sector GHG Emission Trajectories 2018 to 2038

- Four different scenarios are run out to 2038; all four trajectories are consistent with 80% reductions in economy-wide GHG emissions by 2050
- Chart below reflects CAISO (not statewide) GHG targets



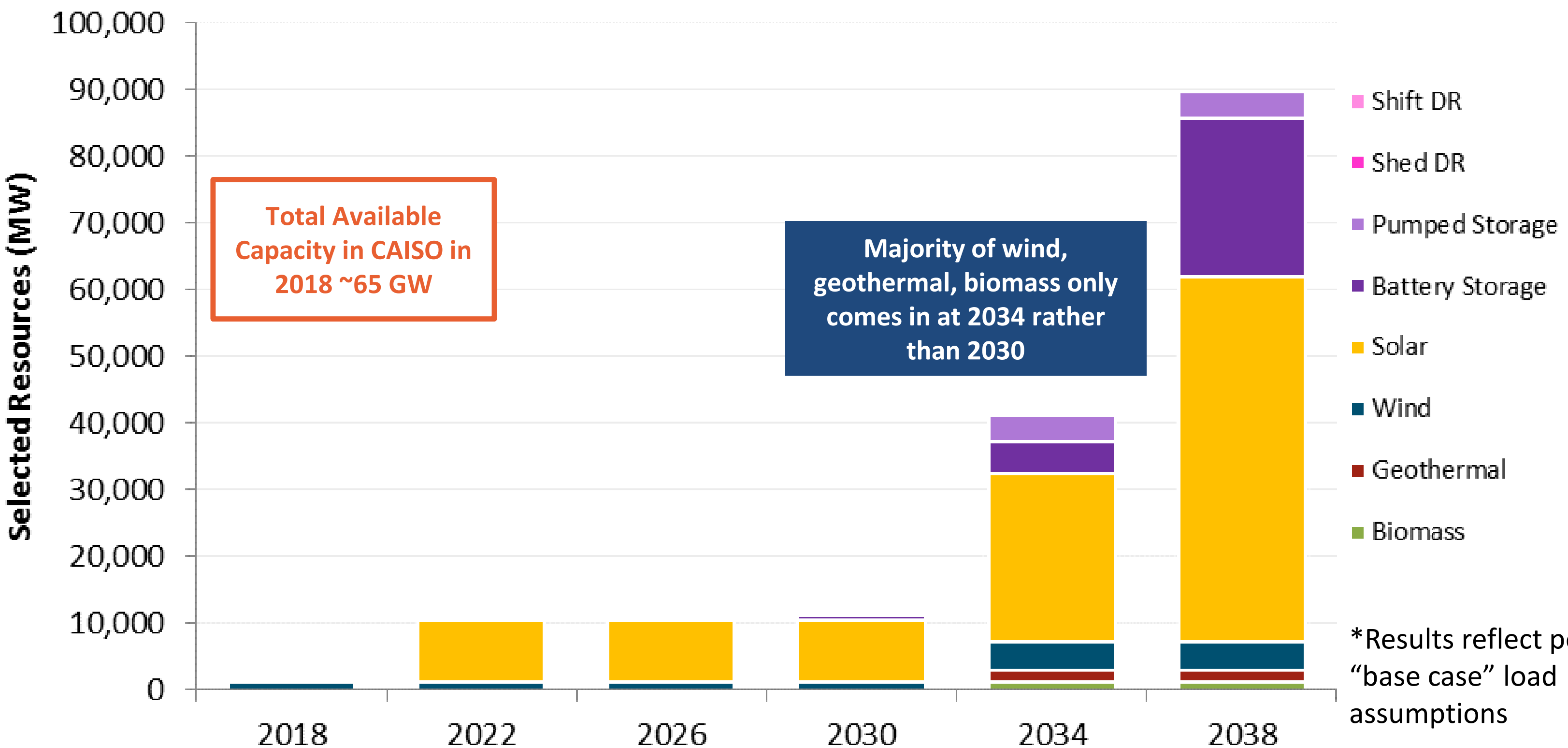
Post 2030 Load Forecasts

- Staff derived load forecasts for each post-2030 scenario from CARB's PATHWAYS economy-wide analysis



Resources Selected by RESOLVE
42 MMT Target – Post 2030 Load*

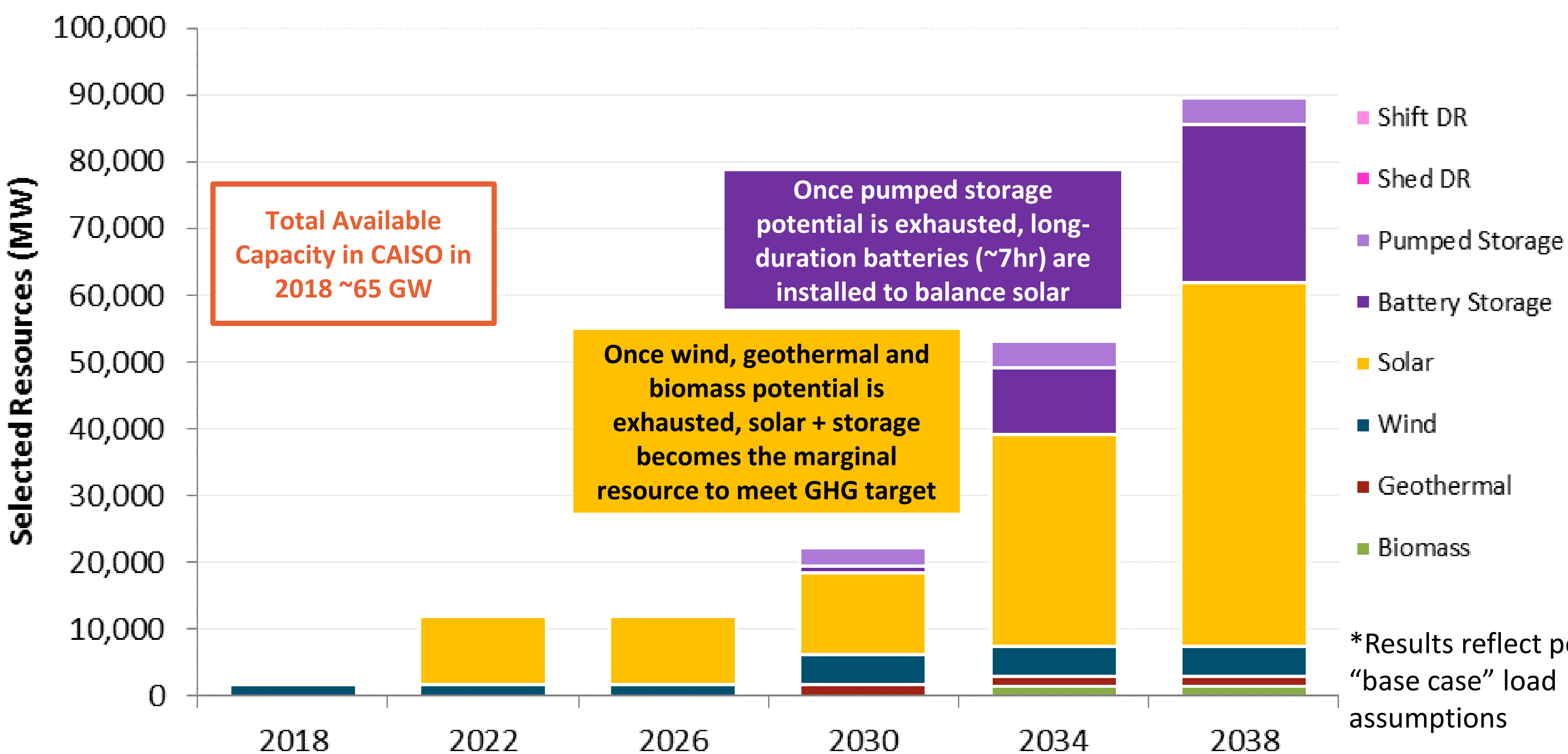
- Achieving 2038 emissions target requires **tens of thousands of MW** of new solar PV and battery storage after 2030 in addition to new geothermal and biomass
- Combination of load growth (EV, hydrogen and electrification loads) and decreasing GHG target drives need for large renewable buildout after 2030



*Results reflect post 2030 "base case" load assumptions

Resources Selected by RESOLVE
30 MMT Target – Base Post 2030 Load*

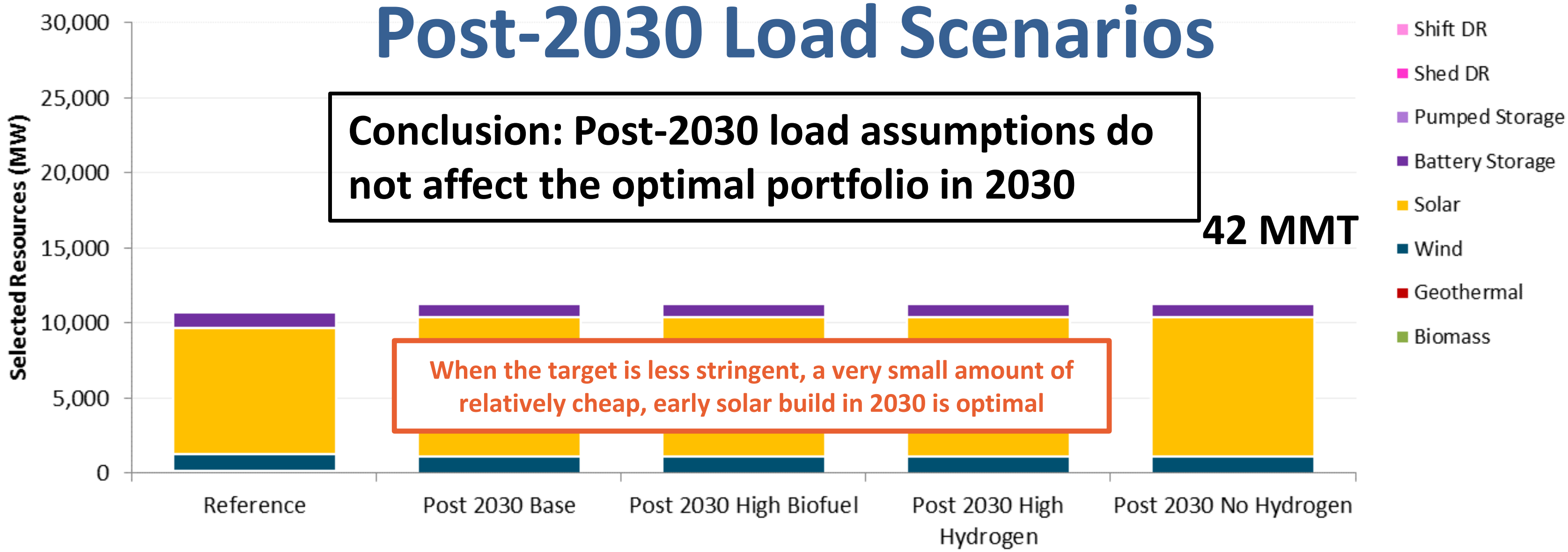
- Lowering the intermediate 2030 target from 42 MMT to 30 MMT accelerates some of the renewable buildout but does not alter final 2038 portfolio
- Accelerating renewable buildout costs about **$8.5 billion** in TRC (present value)

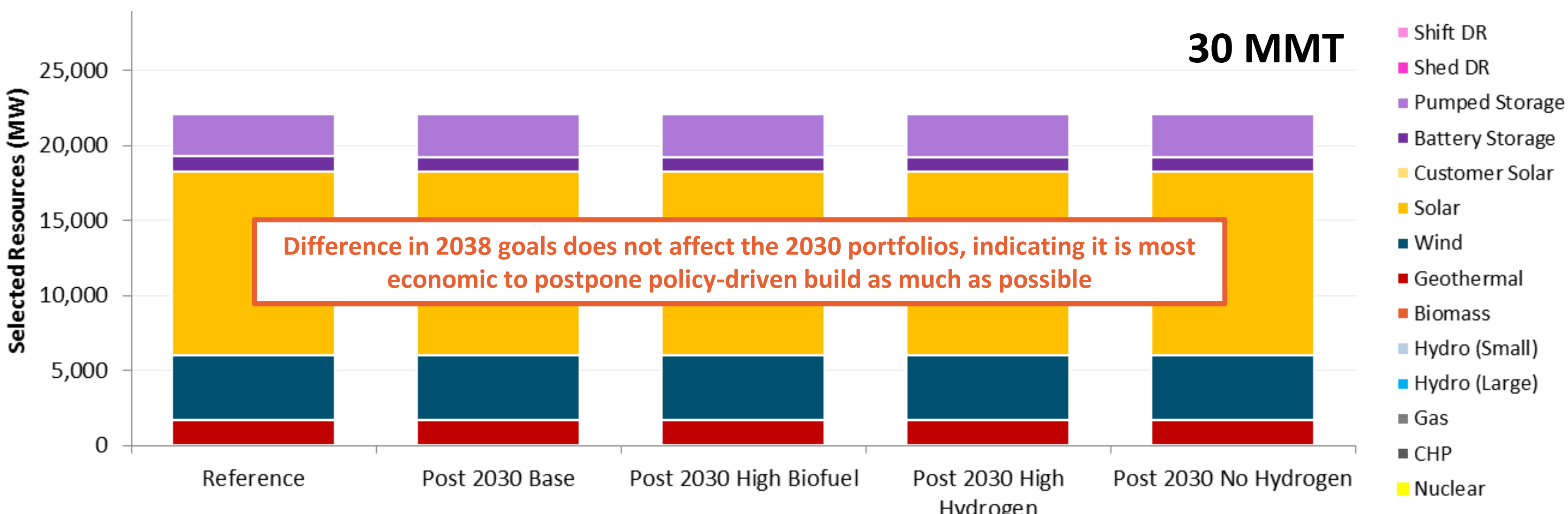


*Results reflect post 2030 "base case" load assumptions

2030 Portfolios with Different Post-2030 Load Scenarios

Conclusion: Post-2030 load assumptions do not affect the optimal portfolio in 2030





NOTE: “Reference” refers to the core 30/42 MMT IRP cases

D.3 SENSITIVITIES RUN IN RESPONSE TO PARTY COMMENTS

Higher RPS Sensitivity: Overview

Sensitivity Question

- What is the effect of a higher RPS vs. a higher GHG target

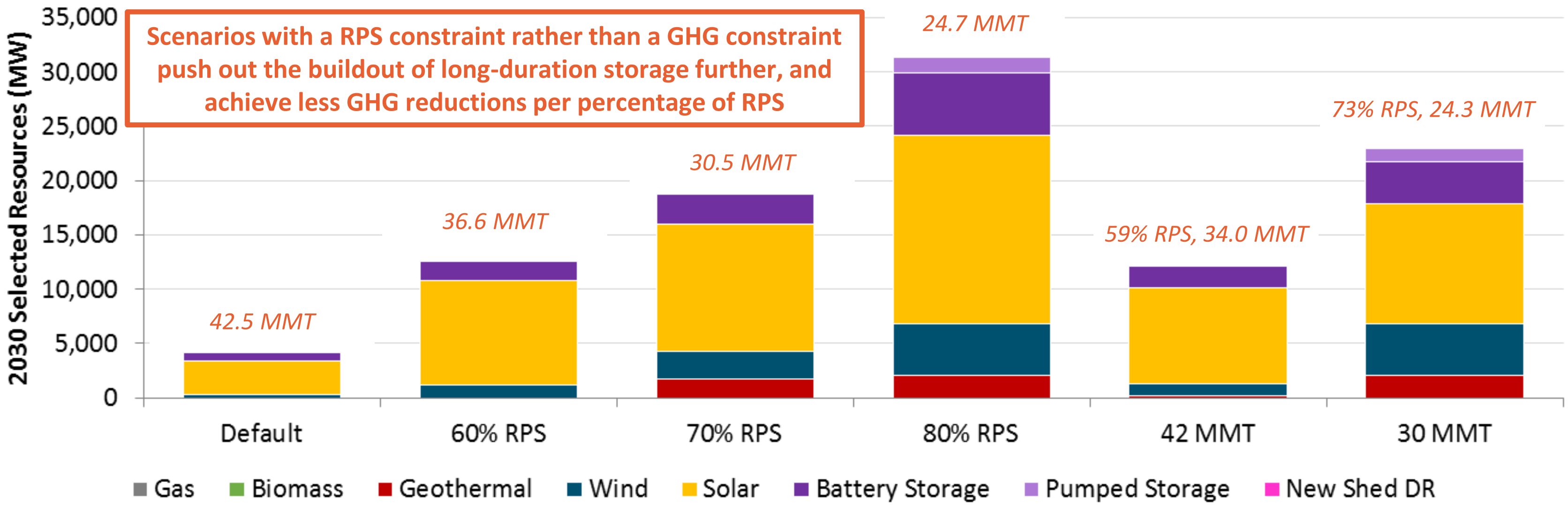
Sensitivity Design

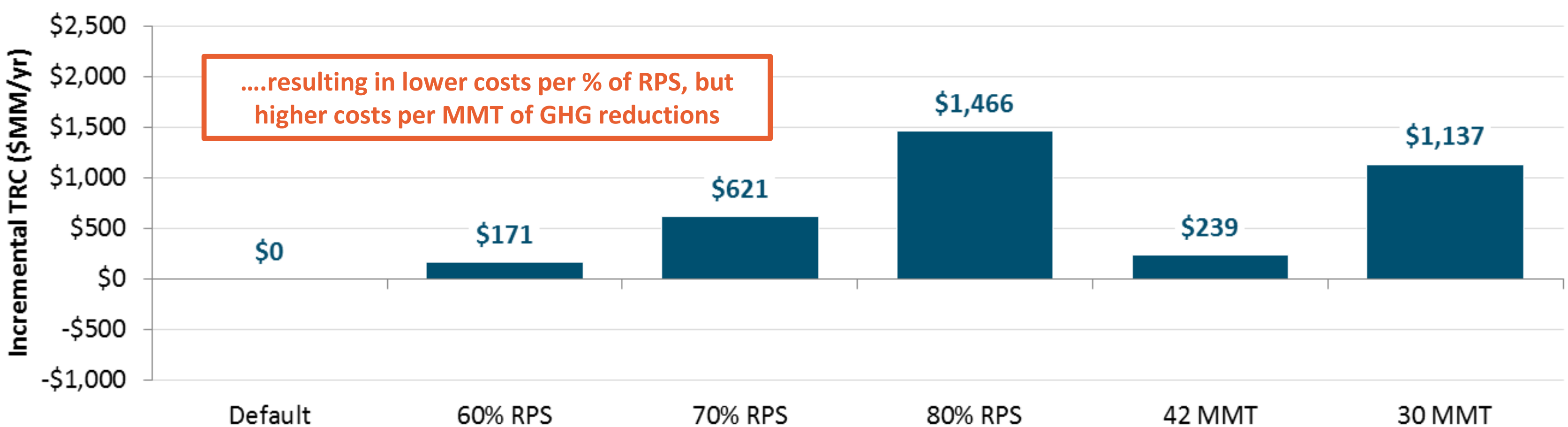
- Increase the RPS for the default case to respectively 60%, 70% and 80%, and compare with the three main policy assumptions (Default, 42 MMT, 30 MMT)

Key Assumptions

- Same as default case, but with a RPS target of respectively 60%, 70%, and 80% by 2030, linearly increasing from 33% in 2020.

Summary Results: Higher RPS





Observations on Higher RPS Sensitivity Results

- According to CARB's GHG accounting rules there are no GHG credits for exporting renewable power. Meanwhile, the current RPS policy allows exports of renewable power while retaining the REC.
- As a result, RPS constrained scenarios will tend to build more cheap solar and export it whenever possible.
- In the equivalent GHG constrained scenario, the renewable power needs to be delivered in-state, and therefore requires either long-duration storage, or a more diverse portfolio (geothermal and wind)
- An RPS policy intended to reduce GHG emissions could lead to lots of renewable power being sent out-of-state while in-state emissions remain relatively high
- Achieving GHG emissions reductions at least cost is California's overarching goal for IRP. The RPS sensitivity shows that a GHG-constrained planning process will achieve this goal more cost-effectively with a clearer market signal than an RPS-centric planning process.
  - The 30 MMT scenario reaches about the same CA GHG emissions as the 80% RPS scenario, but at much lower costs.

Shorter Duration Pumped Storage Sensitivity: Overview

Sensitivity Question

- What is the impact of allowing cheaper, shorter duration pumped storage?

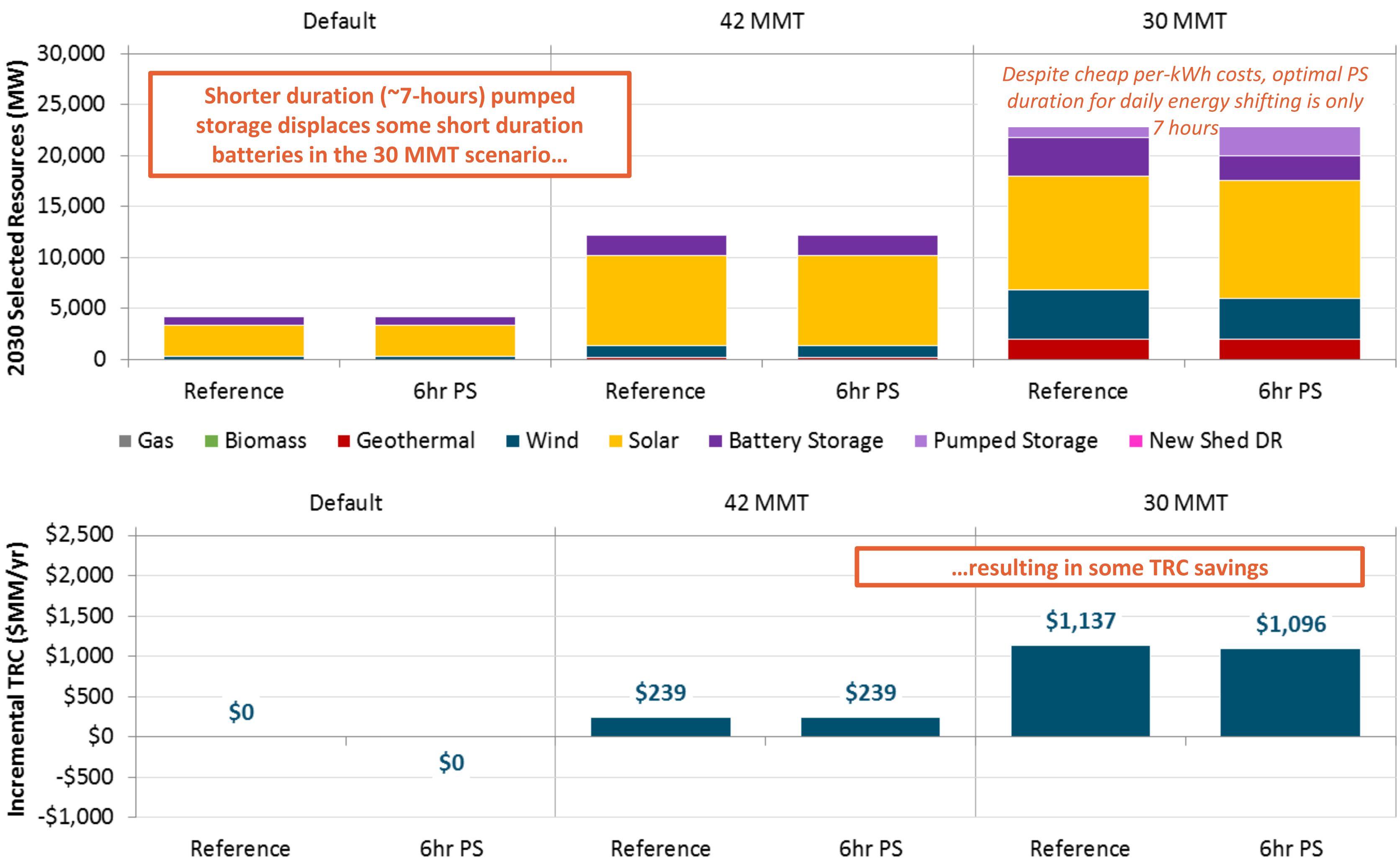
Sensitivity Design

- Decrease the minimum duration of pumped storage under the three main policy assumptions (Default, 42 MMT, 30 MMT)

Key Assumptions

- Decrease minimum duration of pumped storage from 12 hours to 6 hours

Summary Results:
Shorter Duration Pumped Storage Sensitivity



Explanation of Results

- 7 hours of duration turns out to be the most optimal pumped storage (PS) configuration for daily energy shifting, given PS's relative costs of energy vs. power
- Since the reference case requires at least 12-hours of storage, the shorter duration PS sensitivity allows for a cheaper, more optimal PS configuration.
  - As a result, PS will be more competitive with the short-duration batteries, and will displace some of the batteries in scenarios where there is value to load shifting (i.e. the most GHG constrained scenario).
- Note that RESOLVE treats each day's dispatch independently and will inherently not show any value of multi-day storage.

High Carbon Price Sensitivity: Overview

Sensitivity Question

- What is the effect of a higher carbon allowance price?

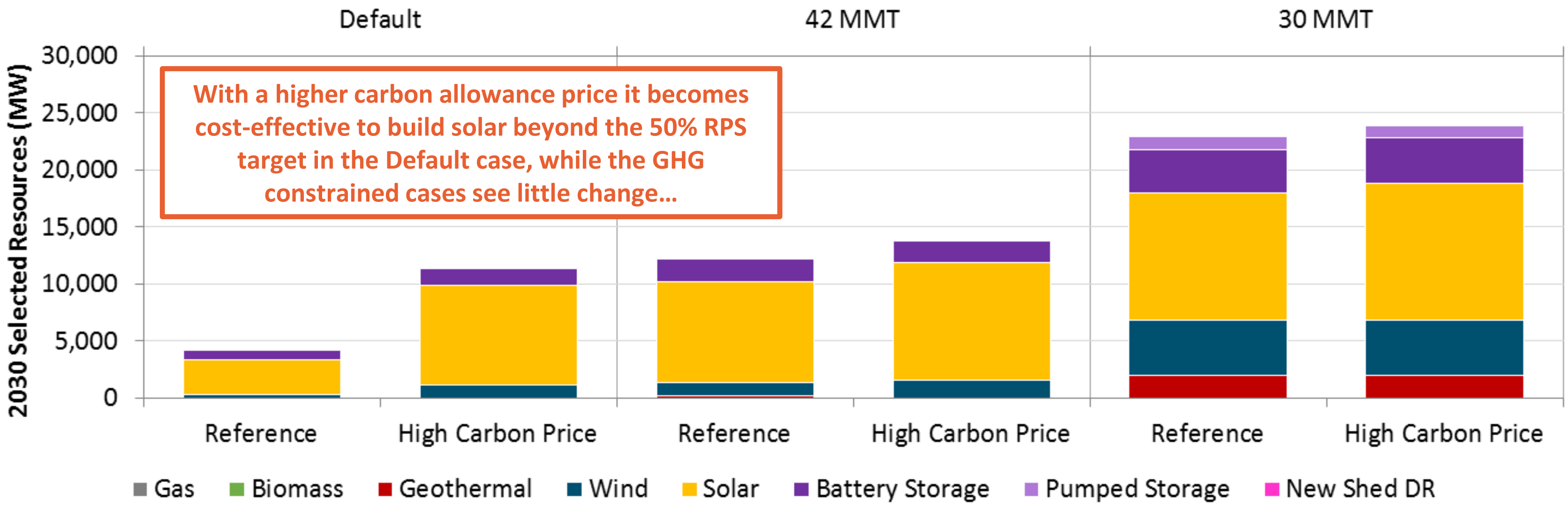
Sensitivity Design

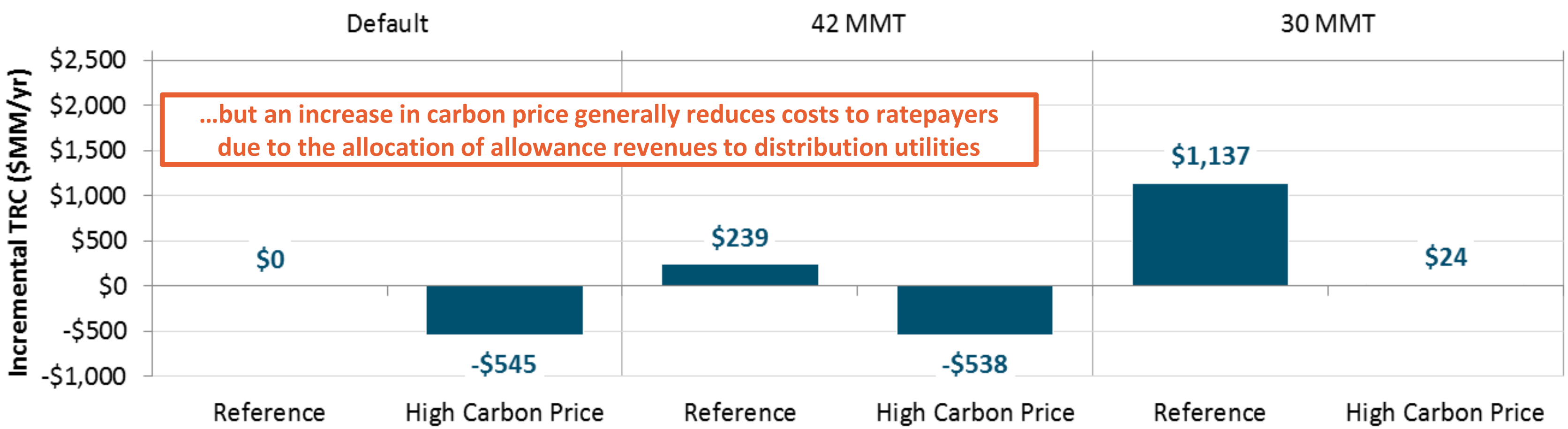
- Increase the carbon allowance price under the three main policy assumptions (Default, 42 MMT, 30 MMT)

Key Assumptions

- 2018 carbon allowance price increases from $15/ton to $45/ton
- 2030 carbon allowance price increases from $29/ton to $88/ton

Summary Results:
High Carbon Price Sensitivity





Explanation of Results

- In the Default case, a higher carbon allowance price makes PV more cost effective with fossil fuels, and results in a renewable buildout beyond the 50% RPS target. The TRC cost goes up because of the buildout of this extra solar, and the additional carbon allowance cost for the remaining fossil fuels burned
- The GHG constrained scenarios (42 MMT and 30 MMT) show little change in the portfolio, as they are already strongly GHG constrained, with a shadow price higher than the sensitivity's high allowance price
- As the GHG target decreases, the total cost of carbon allowances goes down. This decreases the TRC effect of increasing the carbon allowance price
- It is important to note that the increase in carbon allowance costs could be recycled to ratepayers, which would negate the TRC cost effect that is observed but may have distributional impacts

Unconstrained OOS Wind Sensitivity: Overview

Sensitivity Question

- What is the optimal amount of OOS wind and how valuable is it?

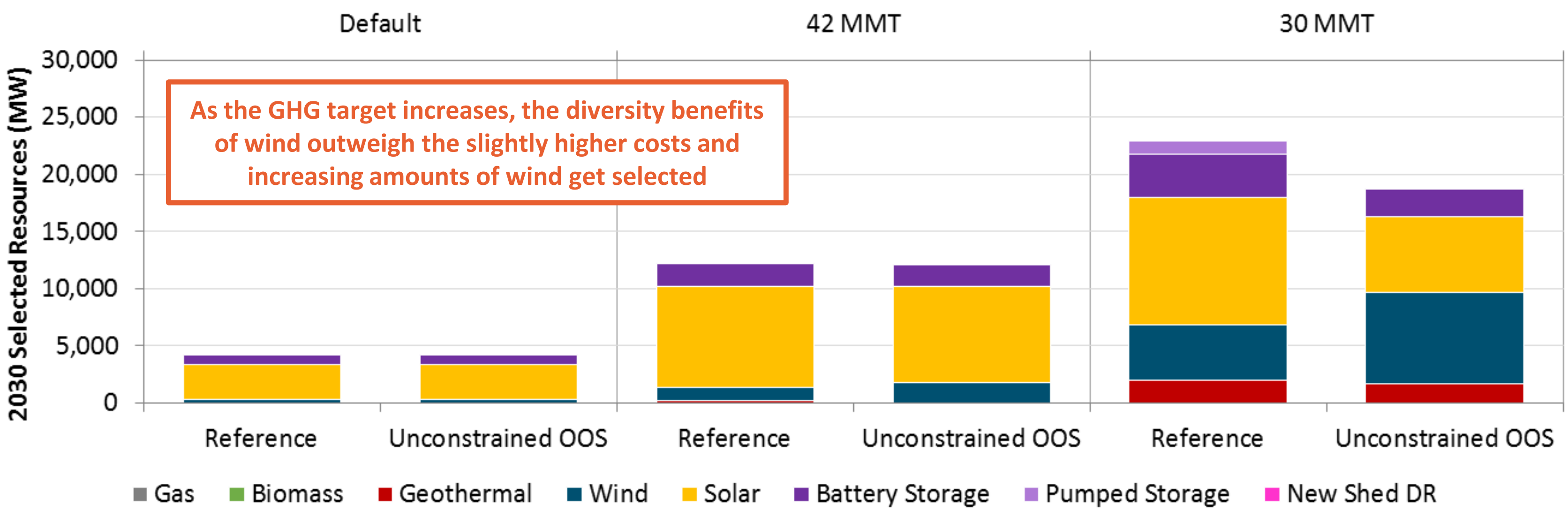
Sensitivity Design

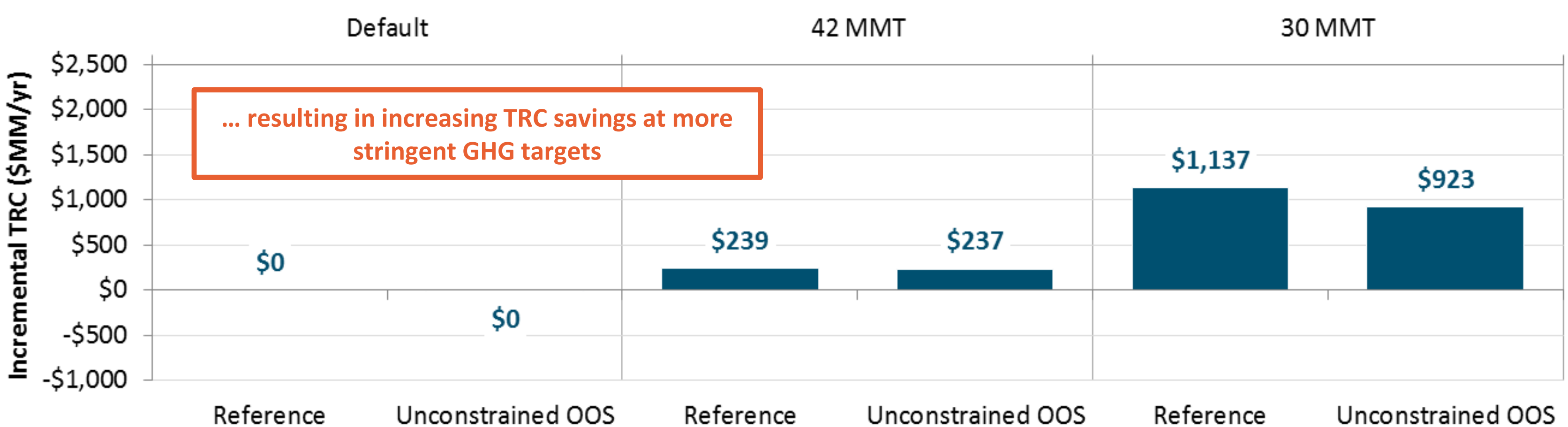
- Allow unconstrained amounts of WY wind and NM wind under the three main policy assumptions (Default, 42 MMT, 30 MMT)

Key Assumptions

- Same as three core cases, except that over 60 GW of WY and NM wind are now available from 2026 onwards

Summary Results: Unconstrained OOS Wind





Explanation of Results

- OOS wind becomes increasingly valuable as renewable penetration and day-time overgeneration increases
- In the 42 MMT case, the availability of high quality OOS wind results in about 600 MW of additional wind with modest TRC savings
- In the 30 MMT case, the model has already selected all the available in-state wind, so any additional wind is much more valuable

Exports Sensitivity: Overview

Sensitivity Question

- What is the effect of lower/higher export limits?

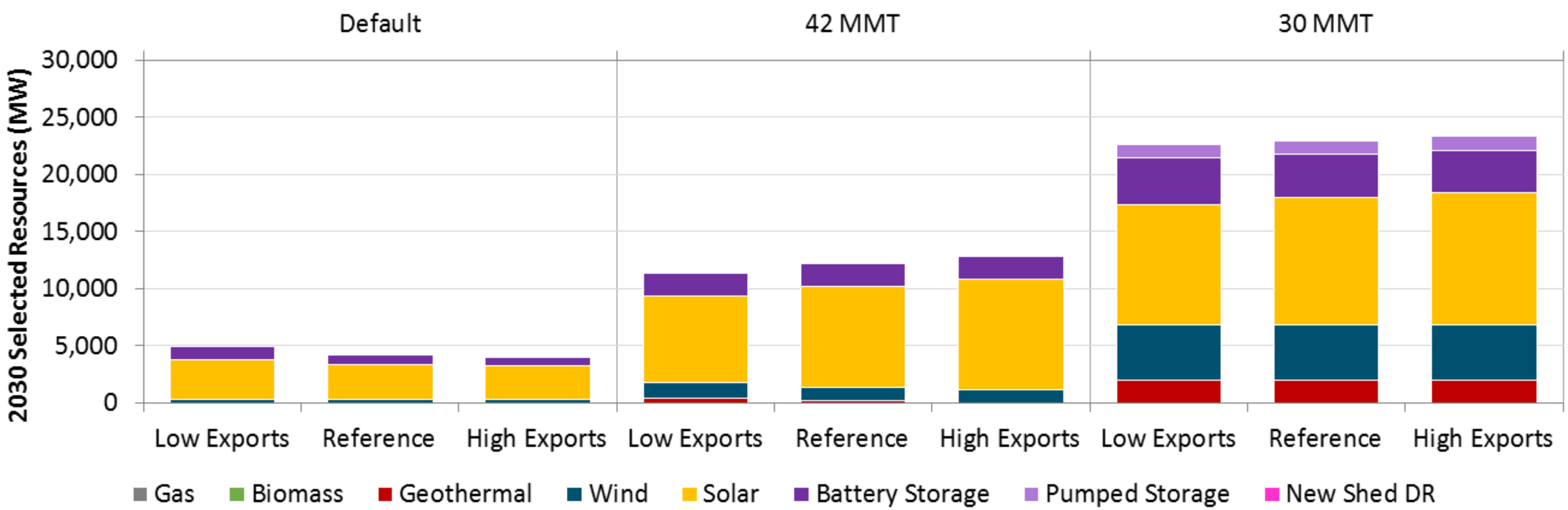
Sensitivity Design

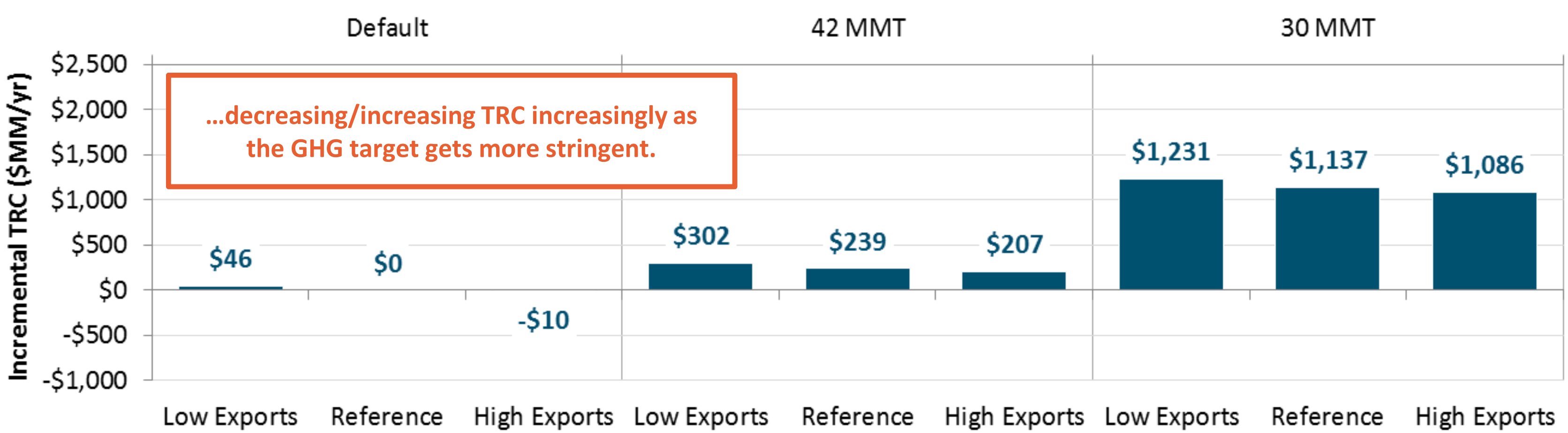
- Increase/decrease the export limit under the three main policy assumptions (Default, 42 MMT, 30 MMT)

Key Assumptions

- High exports sensitivity: 8,000 MW
- Reference: 5,000 MW
- Low Exports sensitivity: 2,000 MW

Summary Results: Export Limits





Explanation of Results

- High export limits alleviate some of the overgeneration that solar causes, resulting in a higher amount of optimal solar buildout
- Low export limits do the opposite, and increase the need for diversification through wind and geothermal, and/or long duration storage – and these resources are more costly, resulting in an increase in TRC
- As the GHG target gets more stringent, overgeneration increases, and the cost savings from alleviating some of the overgeneration with higher exports increase
- Underlines the finding that beyond a certain amount of solar, integration solutions are needed, whether resource diversity, long-duration storage, or increased regional trading